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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769. (U39E)	Rulemaking 14-08-013 (Filed August 14, 2014)
And Related Matters.	A.15-07-002 A.15-07-003 A.15-07-006

(NOT CONSOLIDATED)

In the Matter of the Application of PacifiCorp (U901E) Setting Forth its Distribution Resource Plan Pursuant to Public Utilities Code Section 769.	A.15-07-005 (Filed July 1, 2015)
And Related Matters.	A.15-07-007 A.15-07-008

PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E)
2019 DISTRIBUTION DEFERRAL OPPORTUNITY REPORT
PUBLIC VERSION
(ATTACHMENT A CONTAINS CONFIDENTIAL INFORMATION)

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Dated: August 15, 2019

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Pursuant to Ordering Paragraph 2.d and 2.e of Decision (D.) 18-02-004 and the May 7, 2019, Administrative Law Judge (ALJ) Ruling modifying the Distribution Investment Deferral Framework process, Pacific Gas and Electric Company provides its 2019 Distribution Deferral Opportunity Report (DDOR). The DDOR is attached as Attachment A. Pursuant to Section 3.4 of General Order 66-D and the July 24, 2018, ALJ Ruling in this proceeding, certain data in the DDOR has been determined to be confidential as provided in the Confidentiality Declaration attached to this pleading as Attachment B.

Respectfully Submitted,
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By: */s/ Christopher J. Warner*
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Dated: August 15, 2019

Attachment A

PG&E'S 2019 DISTRIBUTION DEFERRAL OPPORTUNITY REPORT

Together, Building a Better California

August 15, 2019

Executive Summary

Pacific Gas and Electric Company (PG&E) hereby submits its 2019 Distribution Deferral Opportunity Report (DDOR) as directed by the California Public Utilities Commission's (Commission or CPUC) Decision (D.)18-02-004 and the May 7, 2019, Administrative Law Judge Ruling in the Distribution Resources Plan (DRP) Order Institute Rulemaking proceeding. This DDOR is submitted to the Commission, along with PG&E's 2019 Grid Needs Assessment (GNA) Report, to comply with D.18-02-004. This 2019 DDOR builds off PG&E's 2019 GNA Report and identifies candidate distribution deferral opportunities for consideration of competitive solicitations for cost-effective Distributed Energy Resource (DER) solutions to address identified distribution grid needs. This report is not subject to Commission approval and will be provided to the Distribution Planning Advisory Group (DPAG) for review and comment. Specifically, this report will cover the following:

- Section 1 – Distribution Resources Plan Objectives and Background
- Section 2 – Mitigation of Grid Needs Identified in PG&E's 2019 GNA Report
- Section 3 – Planned Investments
- Section 4 – Candidate Deferral Opportunities
- Section 5 – DER Distribution Service Requirements
- Section 6 – Project Costs
- Section 7 – Prioritization Metrics
- Section 8 – Candidate Deferral Opportunities Prioritization
- Section 9 – Contingency Plans
- Section 10 – Recommendations and Next Steps

As part of this report, PG&E has identified 18 Candidate Deferral Opportunities totaling approximately 88 megawatts (MW), which are further categorized and prioritized into the following three tiers:

- Tier 1: Identified three Candidate Deferral Opportunities totaling approximately 18.5 MW. Tier 1 Candidate Deferral Opportunities are relatively more likely to be deferrable.
- Tier 2: Identified three Candidate Deferral Opportunities totaling approximately 2.9 MW. Tier 2 Candidate Deferral Opportunities have identified some red flags that indicate they are unlikely to be successfully deferred now. PG&E recommends not pursuing these Candidate Deferral Opportunities, but to closely monitor status and project conditions and re-evaluate for a future date.
- Tier 3: Identified twelve Candidate Deferral Opportunities totaling approximately 66.9 MW. Tier 3 Candidate Deferral Opportunities have multiple major red flags that have been identified and indicate it is not likely a DER deferral solution can successfully be sourced.

The following table summarizes PG&E's 2019 DDOR Candidate Deferral Opportunities including location, targeted in-service need date, and minimum grid capacity needed (i.e., deficiency).

Table 1: PG&E's 2019 DDOR Candidate Deferral Opportunities Location Summary

Tier	Candidate Deferral Opportunities	In-Service Date	Deficiency (MW)
1	Alpaugh New Feeder	2022	4.4
	Calflax Bank 2	2023	CC
	Santa Nella New Bank & Feeder	2022	9.3
2	Camp Evers 2107	2022	0.9
	FMC 1102	2023	0.8
	Brentwood 2105	2022	1.2
3	Estrella Substation	2024	24.3
	Pueblo Bank 3	2022	23.2
	Oceano 1106	2022	1.2
	Rosedale 2102	2022	1.8
	Rob Roy 2105	2022	3.0
	Peabody 2106	2022	CC
	Madison 2101	2022	CC
	Martin SF H 1108	2022	1.0
	Martin SF H 1107	2022	1.8
	Avenal 2101	2022	CC
	Edenvale 2108	2022	1.5
	Dairyland 1110 New Feeder	2022	4.5

PG&E's recommendation is to pursue competitive solicitations for only the Tier 1 Candidate Deferral Opportunities (three projects totaling 18.5 MW) now. PG&E does not recommend pursuing competitive solicitations for Tiers 2 and 3 currently due to the low likelihood of achieving a successful outcome. However, PG&E recommends closely monitoring the status and conditions of the Tier 2 Candidate Deferral Opportunities for future re-evaluation and consideration of competitive solicitations later.

PG&E will present the Candidate Deferral Opportunities and preliminary prioritization metrics to the DPAG by September 20, 2019. Based on feedback from the DPAG and the Independent Professional Engineer (IPE), PG&E will then submit the Final Candidate Deferral List by November 15, 2019.

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1. Distribution Resources Plan Objectives and Background

On August 14, 2014, the Commission instituted Rulemaking 14-08-013 to establish policies, procedures, and rules to guide the California investor-owned utilities (IOU) in developing their DRP proposals. This rulemaking also established new polices to evaluate the IOUs' existing and future electric distribution infrastructure and planning procedures with respect to incorporating DERs into the planning and operations of their electric distribution systems.

In July 2015, California IOUs each submitted their respective DRP proposals to the Commission. The Commission organized the review of the DRP filing content into three tracks: Track 1 – Tools and Methodologies; Track 2 – Field Demonstration Projects; and Track 3 – Policy Issues. In February 2018 the Commission issued D.18-02-004 on Track 3 Policy Issues, sub-track 1 (Growth Scenarios) and Sub-track 3 (Distribution Investment and Deferral Process). This decision directed the IOUs to file a GNA by June 1 of each year, and a DDOR by September 1 of each year.[1] In May 2019, the assigned Administrative Law Judge (ALJ) issued a ruling modifying the Distribution Investment Deferral Framework (DIDF) process, updating the date upon which the IOUs submit the GNA and DDOR to August 15 of each year.[2] This report fulfills the requirements associated with the DDOR that is not subject to Commission approval and will be provided to the DPAG for review and comment.

1.1. Objectives of the Distribution Deferral Opportunity Report

The objective of the DDOR is to utilize the GNA to identify PG&E's candidate distribution deferral opportunities shortlist. In addition, other objectives of the DDOR are to provide transparency into the assumptions and results of the distribution resources planning process that yield the DDOR candidate shortlist and provide the associated DER attributes required to meet these opportunities.

PG&E notes that the information in this DDOR represents PG&E's best information currently available on its electric distribution system, and is subject to change, including updates based on changes in system forecast and local loads, priorities for emergent work on electric distribution facilities, and the results of PG&E's rate cases, including the 2020 General Rate Case (GRC).

[1] D.18-02-004 O.P. 2.d.

[2] ALJ Ruling, p. 9.

1.2. Regulatory Timelines Associated with DDOR

PG&E's DDOR is required to be filed by August 15 of each year, concurrent with the GNA, and is provided to the DPAG[3] for advisory input. After PG&E files the DDOR and provides it to the DPAG, PG&E is required to initiate DPAG meetings. By November 15 of each year or earlier, PG&E will submit a Tier 2 advice letter requesting approval of the distribution deferral opportunities that were a result of the DPAG's advisory input on the DDOR. Within 30 days of the Commission's disposition of this Tier 2 advice letter, PG&E will launch Competitive Solicitation Request for Offers (RFO) for the identified distribution deferral opportunities.

The regulatory timelines associated with the DDOR and Competitive Solicitations are:[4]

Table 2: DPAG Schedule

Activity Date (on or before)	Date (on or before)
IOUs submit GNA/DDOR	August 15
IPE circulates preliminary analysis	September 10
DPAG Meetings	September 16-20
Participants provide questions and comments to IOUs and IPE	September 23
Follow up meeting via webinar	October 7-8
IPE Final Report	October 21
DIDF Advice Letters Submitted	November 15
Launch RFO for DERs	Within 30 Days of DIDF Advice Letter Approval

Collectively, this process laid out in D.18-02-004 and summarized in Figure 1 below is referred to as the DIDF or the Distribution Resources Planning Process. This report completes the third stage of the process.

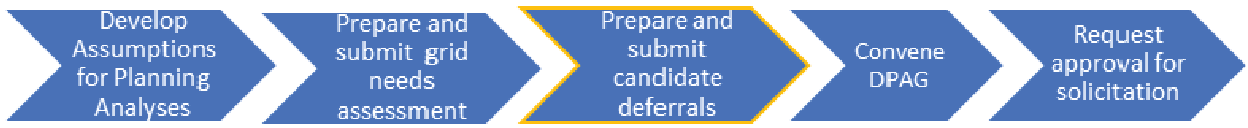


Figure 1: High Level Summary of Distribution Resources Planning Process

[3] As described in D.18-02-004, the DPAG is a distribution planning stakeholder group that provides advisory input on which distribution deferral opportunities should be pursued through competitive solicitation of DER non-wires solutions.

[4] ALJ Ruling, p. 9.

1.3. Distribution Investment Deferral Framework Process

Figure 2 illustrates the Distribution Investment Deferral Process. The process acts as a funnel to identify candidate deferral projects, based on the grid needs identified in the GNA.

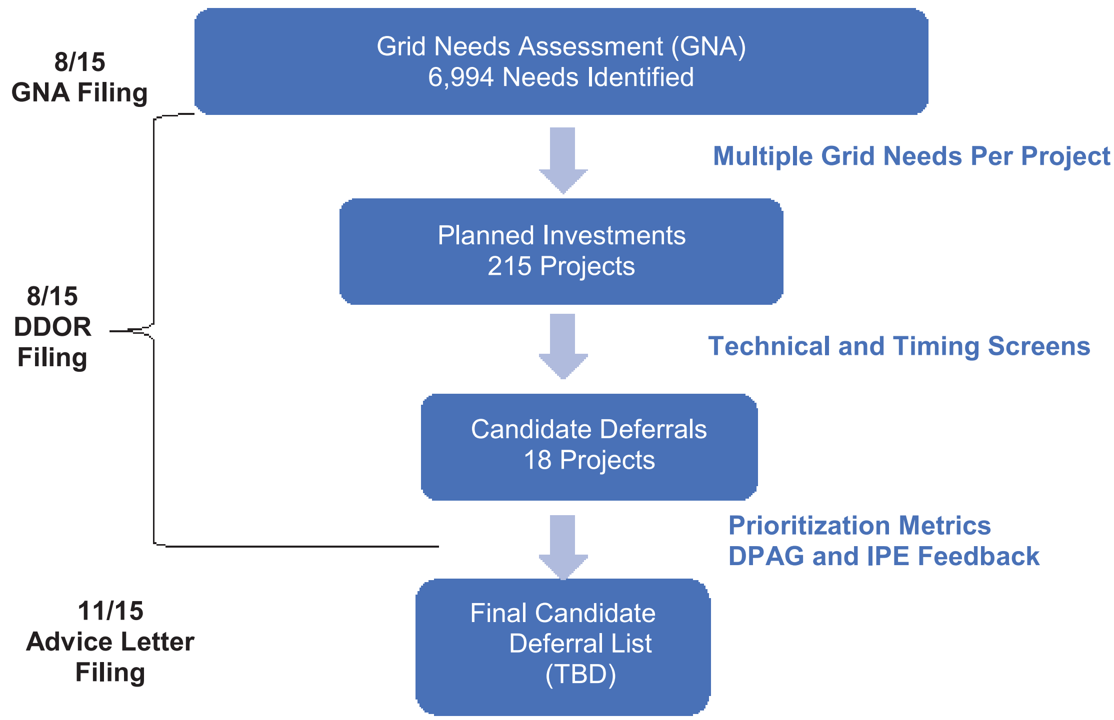


Figure 2: Illustration of Process to Identify Final Candidate Deferral Opportunities from GNA

PG&E's 2019 GNA filing identified 6,994 grid needs. The grid needs for the 2019 GNA included substation, feeder, and line section needs. The GNA identified distribution capacity, reliability (back-tie), voltage, and resiliency (microgrid) needs. In contrast to PG&E's 2018 GNA, PG&E's 2019 GNA load forecast includes future planned load transfers and switching operations that do not require a capacity project. Therefore, PG&E's 2019 GNA only includes identified grid needs that cannot be mitigated via distribution switching and load transfers that do not require a capacity project.

A single Planned Investment project may mitigate multiple grid needs that are identified in the GNA. Based on the 2019 GNA, PG&E identified 215 Planned Investments. After applying the technical and timing screens, PG&E identified 18 Candidate Deferral Opportunities.

The Candidate Deferral Opportunities and prioritization metrics will be presented to the DPAG in September 2019. Section 10.1 provides a proposed workplan and agenda for the DPAG meeting. After incorporating feedback from the DPAG and the IPE, PG&E will then submit the Final Candidate Deferral List by November 15, 2019.

1.4. Summary of PG&E's 2019 GNA Report

The following sections describe the study methodology and assumptions used to forecast and identify distribution grid needs in PG&E's 2019 GNA submittal.

1.5. PG&E's Distribution Resources Planning Horizon

To align with the circuit-level planning assumption requirements provided in D.18-02-004, PG&E used a 5-year forecast as the study horizon for identifying grid needs. For the 2019 GNA submittal, PG&E provided the assessment for the 5-year planning horizon for the years 2019 through 2023. PG&E identifies needs for line section and volt/var needs for a three-year period, and PG&E's 2019 GNA submittal therefore includes needs for line segments and volt-var for the years 2019 through 2021.[5]

1.6. PG&E's Distribution System Load Forecast Assumptions

PG&E's load growth forecast begins with the most recently approved California Energy Commission (CEC) PG&E Transmission Access Charge area Peak and Energy Forecast: Mid Baseline growth forecast.   Transmission-connected load growth and known new distribution loads are deducted from the CEC system load growth forecast.[6] The resultant growth is distributed out by customer class (residential, industrial, commercial, and agricultural) and is then allocated to PG&E's distribution feeders using geospatial analysis.

PG&E uses the LoadSEER Geographic Information System (GIS) geo-spatial forecasting program, created by Integral Analytics. This program uses satellite imagery and proprietary data analytics to score each acre in PG&E's territory for the likelihood of increased load by customer class.

1.7. PG&E's Distribution System DER Growth Forecast Assumptions

Separate from load growth, PG&E has incorporated DER adoption into its distribution bank and feeder forecast assumptions. This is accomplished for residential photovoltaic (PV), retail non-residential PV, energy efficiency for different customer classes, electric vehicles, and load modifying demand response.[7] The starting point for developing these

[5] ALJ Ruling, p. 6.

[6] Known new distribution loads are deducted from the system-wide forecast so that they can be added back in as local new load adjustments while maintaining consistency with the CEC forecast in aggregate.

[7] Load Modifying Demand Response reshapes or reduces the net load curve as opposed to Supply Resource Demand Response which is integrated into the California Independent System Operator energy markets.

feeder level DER growth forecasts is the CEC's California Energy Demand (CED) forecast that is completed at the system-wide level.

Staying consistent with the CED forecast, the system-wide incremental MW capacity by DER technology type is allocated to the feeders based on allocation methodologies specific to the DER types. Variables used to allocate incremental DER capacity geospatially include consumption by customer class, amount of generation by feeder, historical PV system adoption by zip code, the s-curve trending model, observed distributed generation penetration level, daily peak diversity factors, weather zones, and many other factors specific for each type of DER.[8] Consistent with the Assigned Commissioner's Ruling on the adoption of DERs Growth Scenarios issued August 9, 2017, and the assigned Administrative Law Judge's Ruling on the Distribution Working Group Progress Report issued August 1, 2018, PG&E's Distribution System DER Growth Assumptions utilize:

- CED Update 2017 Mid Baseline PV Generation
- CED Update 2017 Mid Baseline Electric Vehicles
- CED Update 2017 Mid Baseline Energy Storage
- CED Update 2017 Mid Baseline Load Modifying Demand Response
- CED Update 2017 Mid Baseline-Low Additional Achievable Energy Efficiency

PG&E did not incorporate a specific feeder allocation methodology for energy storage since it is still under development. However, the forecasted growth of energy storage functioned to reduce the overall system level growth forecast.

1.8. PG&E's Load Transfers and Switching Assumptions for 2019 GNA

PG&E's 2019 GNA load forecast includes the impact of future planned load transfers and switching operations that do not require a capacity project. The planned load transfers and switching operations are used to balance the load between feeders and banks. Typically, planned load transfers and switching operations, which are utility industry common best practices, are the lowest cost alternatives that take advantage of available existing "back-tie" interconnections and capacity on adjacent distribution feeders and banks.

It is important to note that PG&E's 2018 GNA did not include any planned load transfers or switching operations in the 2018 GNA load forecast.[9] Conversely, PG&E's 2019 GNA

[8] PG&E's DER Growth Forecast Assumptions are subject to updating and revision on an annual basis in accordance with distribution planning criteria and guidance provided by the Commission.

[9] PG&E's 2018 DDOR, p. 11.

only includes identified grid needs that require a capacity project either to directly mitigate or to enable distribution switching and load transfers that mitigate the grid need.

1.9. Grid Needs Assessment Scope

The scope of the 2019 GNA was defined in D.18-02-004 and updated via a May2019 ALJ Ruling.[10] PG&E's 2019 GNA includes substation/bank, feeder, and line section needs. As adopted in D.18-02-004, grid needs that are reported in this GNA submittal are limited to the forecast deficiencies associated with the four distribution services that DERs can provide as adopted in D.16-12-036, which are distribution capacity, voltage support, reliability (back-tie) and resiliency.

1.10. Customer Confidentiality and Critical Energy Infrastructure Information

To respect and protect customer privacy, PG&E follows aggregation and anonymization rules. Areas that do not meet these requirements are listed in both the redacted version of the GNA Report and the redacted version of this report as "Customer Confidential."

2. Mitigation of Grid Needs Identified in PG&E's 2019 GNA Report

PG&E's 2019 GNA Report is the basis for the Planned Investments and Candidate Deferral Opportunities included in this report. The GNA identified 6,994 needs across the PG&E service territory. These grid needs are either monitored[11] or mitigated by planned facility re-rates[12] or Planned Investments. A single Planned Investment may mitigate multiple grid needs that are identified in the GNA. Figure 2 summarizes how the grid needs identified in PG&E's 2019 GNA Report are used to identify Planned Investments and Candidate Deferral Opportunities in this report.

3. Planned Investments

As described in Section 2, there are 797 distribution grid capacity, 44 reliability (back-tie), 6,153 voltage support, and no resiliency (microgrid) needs identified in the 2019 GNA Report that are mitigated by substation, feeder, and line section Planned Investments. Appendix A shows the resulting Planned Investments.

In total, there are 215 substation, feeder, and distribution line section Planned Investment that mitigate the 6,994 grid needs, because one Planned Investment may mitigate several grid needs. Table 3 summarizes the Planned Investments by project type and by Distribution Planning Region. The Planned Investments consist of

[10] ALJ Ruling, p. A1-A2.

[11] For facilities that are forecasted to have a small overload for a short period of time, PG&E may monitor that forecasted overload as part of its engineering review in the annual distribution planning process rather than identify a planned transfer or planned investment.

[12] In rare instances equipment can be temporarily re-rated following testing and an operational history review to allow for project lead time.

substation projects (e.g., banks), feeders, and distribution line section projects (e.g., installation of switches). The Planned Investments are predominately located in the Central Coast, Central Valley, and Northern Distribution Planning Regions.

Table 4 summarizes the Planned Investments by Distribution Service. The majority of Planned Investments are for Distribution Capacity. Table 5 summarizes the Planned Investments by in-service date. One hundred and ninety-seven (197) Planned Investments have an in-service date within the next three years, and 18 Planned Investments have an in-service date of 2022 or later. All line section Planned Investments have in-service dates within the next three years, because PG&E identifies needs for line section and volt/var needs for a three-year period.[13] Table 6 summarizes the Planned Investments by Locational Net Benefits Analysis (LNBA) range. The methodology used in calculating the LNBA range is included in Section 6.2.

Table 3: Summary of Planned Investments by Distribution Planning Region and by Project Type

Distribution Planning Region	Project Type			Total
	Substation/Bank	Feeder	Distribution Line	
Bay Area	2	5	9	**16**
Central Coast	7	7	41	**55**
Central Valley	9	23	67	**99**
Northern	3	3	39	**45**
Totals	**21**	**38**	**156**	**215**

Table 4: Summary of Planned Investments by Distribution Service

Distribution Service				Total
Distribution Capacity	Voltage Support	Reliability (Back-Tie)	Resiliency	
129	50	36	0	215

Table 5: Summary of Planned Investments by In-Service Date

In-Service Date						Total
2019	2020	2021	2022	2023	2024	
77	76	44	15	2	1	215

[13] ALJ Ruling, p. 6.

Table 6: Summary of Planned Investments by LNBA Range

LNBA Range ($/kW-yr)						Total
$0	$0-$50	$50-$100	$100-$200	$200-$500	>$500	
0	106	20	20	8	11	165
LNBA Range ($/Vpu-yr)						**Total**
$0	$0-$0.50	$0.50-$1	$1-$2	$2-$5	>$5	
0	17	26	5	0	2	50

4. Candidate Deferral Opportunities

As illustrated in Figure 1, the application of screens to the Planned Investments list (Appendix A) results in the identification of the Candidate Deferral Opportunities. D.18-02-004 requires the application of two screens: (1) technical screen and (2) timing screen. These two screens are further described in the following sections.

4.1. Technical Screen

The purpose of the Technical Screen is to identify the Distribution Services that DERs can provide to potentially defer a distribution project. The following definitions for the key distribution services that DERs can provide were adopted by D.16-12-036, *Decision Addressing Competitive Solicitation Framework and Utility Regulatory Incentive Pilot*, issued December 22, 2016:

1 Distribution Capacity services are load-modifying or supply services that DERs provide via the dispatch of power output for generators or reduction in load that is capable of reliably and consistently reducing net loading on desired distribution infrastructure.

2 Voltage Support services are substation and/or feeder level dynamic voltage management services provided by an individual resource and/or aggregated resources capable of dynamically correcting excursions outside voltage limits as well as supporting conservation voltage reduction strategies in coordination with utility voltage/reactive power control systems.

3 Reliability (back-tie) services are load-modifying or supply service capable of improving local distribution reliability and/or resiliency. Specifically, this service provides a fast reconnection and availability of excess reserves to reduce demand when restoring customers during abnormal configurations.

4 Resiliency (micro-grid) services are load-modifying or supply services capable of improving local distribution reliability and/or resiliency. This service provides a fast reconnection and availability of excess reserves to reduce demand when restoring customers during abnormal configurations.

The technical screen was applied to the 2019 GNA, upon which this report is based. The needs and Planned Investments identified in PG&E's 2019 GNA and DDOR are limited to the four Distribution Services listed above. PG&E's 2019 GNA and DDOR include substation, feeder, and line section needs and Planned Investments.

4.2. Timing Screen

The purpose of the Timing Screen is to ensure that cost-effective DER solutions can be procured with sufficient time to fully deploy and begin commercial operation in advance of the forecast need date. For this year, PG&E is using the Competitive Solicitation Framework and a 2022 or later in-service date which is considered adequate time for DER developers to design, develop, market and deploy the DER solution as well as to minimize the cost of providing for a contingency plan should the DER procurement be unsuccessful. As shown in Table 5, 197 out of 215 projects were filtered out of the Planned Investments list using the timing screen.

4.3. Candidate Deferral Opportunities

The application of the timing and technical screens results in 18 Candidate Deferral Opportunities, as shown in Appendix B. Table 7 summarizes the Candidate Deferral Opportunities by Project Type and by Distribution Planning Region. Table 8 summarizes the Candidate Deferral Opportunities by Distribution Service. The majority of the Candidate Deferral Opportunities are Distribution Line projects for Reliability (Back-Tie) or Capacity service. Table 9 summarizes the Candidate Deferral Opportunities by In-Service Date. Due to the application of the timing screen, all Candidate Deferral Opportunities have an In-Service Date of 2022 or later. Table 10 summarizes the Candidate Deferral Opportunities by LNBA Range. The methodology used in calculating the LNBA range is included in Section 6.2.

Table 7: Summary of Candidate Deferral Opportunities by Project Type and Distribution Planning Region

Distribution Planning Region	Project Type			Total
	Substation/ Bank	Feeder	Distribution Line	
Bay Area	1	0	3	**4**
Central Coast	1	2	3	**6**
Central Valley	2	2	2	**6**
Northern	0	0	2	**2**
Totals	**4**	**4**	**10**	**18**

Table 8: Summary of Candidate Deferral Opportunities by Distribution Service

Distribution Service				Total
Distribution Capacity	Voltage Support	Reliability (Back-Tie)	Resiliency	
5	0	13	0	**18**

Table 9: Summary of Candidate Deferral Opportunities by In-Service Date

In-Service Date						Total
2019	2020	2021	2022	2023	2024	
0	0	0	15	2	1	**18**

Table 10: Summary of Candidate Deferral Opportunities by LNBA Range

LNBA Range ($/kW-yr)						Total
$0	$>0-$50	$50-$100	$100-$200	$200-$500	>$500	
0	**10**	**6**	**0**	**2**	**0**	**18**

5. DER Distribution Service Requirements

For each of the Candidate Deferral Opportunities listed in Appendix B, the DER distribution service requirements were defined for each grid need. Since each Candidate Deferral Opportunity may mitigate one or more grid needs, there may be one or more set of DER distribution service requirements for a given Candidate Deferral Opportunity. All the DER distribution service requirements for a given Candidate Deferral Opportunity are necessary to defer the investment.

The following annual DER service requirements were determined for each facility: months required, number of calls per year, estimated hours of need, and maximum duration (hours) per call of required DER distribution service.[14] To determine these requirements, PG&E evaluated the forecast peak load on each facility over the span of one year, using an interpolated 8,760-hour load profile[15] to determine when the overloads occur. The basis for the DER distribution service requirements was determined from the highest overload for the period from the in-service date until the end of the 10-year forecast horizon. Therefore, the distribution service requirement may be based on a later year than need included in the GNA or in the Planned Investments list (Appendix A), which used a 5-year forecast as the study horizon for identifying grid needs. Using the interpolated 8,760-hour load profile, PG&E calculated the months, the number of days in the year, and the timespan and duration in which the electric facility is projected to overload or require the distribution service. Load transfers associated with new capital upgrade projects are excluded to ensure consistency between projects since some of these load transfers require part of the project to be completed.

For the Candidate Deferral Opportunities with reliability needs, PG&E identified operational requirements that include Real Time (RT) dispatch capability (i.e., within 5 minutes[16]) in order for the DERs to defer the project. These reliability needs are driven by the need to reduce the impact of outages. Therefore, the need could arise at any time during the year. For Candidate Deferral Opportunities where there is an existing back-tie with a capacity constraint, the operational requirements require Real Time dispatch of capacity to enable the remaining load to be transferred to the back-tie. For Candidate Deferral Opportunities where there is no existing back-tie (and the Planned Investment is to install a new back-tie or mainline loop), the operational requirements require Real Time dispatch of capacity and the ability to balance the load in an islanded state (i.e., operate as a microgrid).

5.1. Operational Requirements

Utilities use standard equipment sizes that have been identified to provide cost-effective service to its customers. Generally, these standard equipment sizes reduce engineering design, equipment maintenance and spare equipment costs. When a system deficiency is mitigated, standard equipment sizes are used, which normally

[14] The DER service requirements were combined for a Candidate Deferral Opportunity where the same operational requirements could meet several gird needs. For example, the DER service requirements for a feeder need and bank need were combined into one requirement where possible (e.g., for the Dairyland 1110 New Feeder Candidate Deferral Opportunity).

[15] The 8,760-hour profile is based on the 576-hour profile created in LoadSEER, organized by Month, Hour, and Weekday vs Weekend. Each of the LoadSEER data points was mapped to the corresponding hour in the 8,760-hour profile.

[16] Dispatch time may vary depending on location and availability of Supervisory Control and Data Acquisition (SCADA)

provides additional capacity to the system beyond the identified need. This additional capacity provides the ability to maintain loading and voltage requirements as well as the ability to transfer load for planned and emergency situations. This ability to operate the system on an on-going basis is often called operational flexibility.

Distribution planning projects typically add capacity in increments based on a standard bank or feeder size, rather than sizing exactly to the grid need. For example, PG&E's current standard distribution bank sizes are 16, 30, and 45 Megavolt-Ampere (MVA). For example, PG&E's Santa Nella Project proposes to replace the existing 10.5 MVA bank with a 30 MVA transformer. The added transformer capability will meet the grid need even if there is uncertainty in the load forecast. In contrast, the total DER distribution service requirement listed for Santa Nella is 9.3 MW. While the DER service requirement would potentially defer the Planned Investment, it does not provide any margin for load forecast uncertainty and does not allow for new customer load interconnections larger than the service requirement amount. If the grid need were to increase, the DER service requirement would no longer be sufficient, and the project would not be deferred. In addition, new load applications for service would likely be delayed while additional DERs were contracted or capacity projects were built. Alternatively, introducing a margin for the DER distribution service requirement, while increasing the likelihood of deferral, would increase the difficulty of procurement or ability to interconnect cost effectively. PG&E is not including any margin in the distribution service requirement in this DDOR. Therefore, even if resources are procured to meet the exact grid need, the project investment may still be required if the load forecast changes and the grid need is no longer met by the procured resources.

The identified Planned Investments also provide operational flexibility beyond meeting the identified grid need. For example, a transformer is available all hours, and load can be transferred to the bank from other feeders or banks as needed to provide additional operational flexibility. In contrast, the DER distribution service requirements only specify the hours of the grid need.

6. Project Costs

6.1. Unit Costs

The estimated cost accuracy of a project is based on the stage of project development. For projects in early stages of development, costs are estimated using either estimates of specific equipment and unit costs for work required, or historical costs from completed projects. As the project develops and scope details become defined, the estimated project costs are adjusted based upon the detailed scope of work. Differences between the unit costs shown in Appendix B and the costs in a GRC are generally due to:

- A GRC has a limited time window. Some projects are expected to have significant costs that occur outside of this window.

- A GRC includes escalated cost estimates. Unit costs are usually a fixed time value and are not escalated.

6.2. Locational Net Benefits Analysis (LNBA)

The LNBA values were calculated using the Energy and Environmental Economics, Inc. (E3) LNBA tool methodology[17] with the following inputs:

- Unit Cost: See section 6.1 for detailed description. Values are based on 2019-unit costs.
- Discount Rate: PG&E used a 7% discount rate. This discount rate is PG&E's after-tax weighted average cost of capital and reflects CPUC authorized cost of equity, cost of debt, and capital structure, as well as current tax rates.
- Deferral Time: PG&E used a deferral time frame from the in-service date of the Candidate Deferral Opportunity until the end of the 10-year forecast horizon. [18] For Planned Investments, PG&E used a deferral time frame from the in-service date until the end of the 5-year planning horizon.
- Capacity (MW) of Deferral: PG&E used a sum of the individual grid needs, assuming each grid need was independent.[19]
- Voltage Service of Deferral: PG&E used the worst case voltage addressed by any single voltage correction project. A nominal voltage was assumed for each line section.

The approach used here is a preliminary methodology subject to change as LNBA is refined and as the DER requirements for this distribution service are refined with experience. The LNBA values in PG&E's 2019 DDOR include only the deferral value from the LNBA tool. For simplicity, 2019 Unit Costs are assumed. To derive the LNBA value, the deferral value output from the E3 tool was divided by the number of years of deferral (equivalent to the Deferral Time above) and the magnitude of need (MW, Vpu).

6.3. Distribution Capital Per Customer Metric

Given that PG&E did not file a GRC during the 2019 DIDF cycle, PG&E does not have a distribution capital per customer metric included in its 2019 DDOR.

6.4. Payments Made to DER Projects

In accordance with Order D.18-02-004 paragraph 2.dd, PG&E is to provide itemized data payments made to DER projects versus the estimated traditional spending such

[17] E3 LNBA Tool V2.11; https://e3.sharefile.com/share/view/sb2965cf362c48399

[18] May 2019 ALJ Ruling, p. 12.

[19] For capacity projects not driven by a thermal capacity overload (e.g., new feeder projects), PG&E used the ratio of the need (e.g., amperage or customer counts) times the capacity of the asset.

deferral projects were able to avoid. To date, PG&E has not made any such payments, and so has no data to report in the 2019 DDOR.

7. Prioritization Metrics

In D.18-02-004, three metrics were adopted to characterize and help prioritize projects on the Candidate Deferral Opportunities shortlist. These metrics are: (a) Cost-Effectiveness, (b) Forecast Certainty, and (c) Market Assessment. Each IOU is to apply these metrics using its own approach provided the metrics support the deferral of any project that can be cost-effectively deferred by DERs.

PG&E has evaluated each of these metrics qualitatively, grouping the Candidate Deferral Opportunities into tiers based on their relative rankings. These qualitative rankings are based on quantitative data as well as engineering judgement by utility distribution planners where noted.

7.1. Cost Effectiveness Metric

Higher tiered projects under the Cost Effectiveness Metric are characterized by:

- High LNBA ($/kW-year)
- High Unit Cost of Traditional Mitigation
- High Converted LNBA per MWh of deferral ($/Megawatt-hour (MWh)-year)
- Judgement based on experience with pilots

The cost effectiveness metric is intended to provide a relative indication of how likely DER resources can cost effectively defer a Planned Investment. The expected performance and operational requirements will be used to calculate the MWh of deferral. Judgement based on experience with pilots incorporates the lessons learned from PG&E's DRP Demonstration Projects C and D RFOs. For example, in these RFOs PG&E obtained learnings that baseload requirements may be difficult to obtain cost-effectively from DERs. The Independent Evaluator reported, "it may be best for PG&E to target circuit needs for future DRP RFOs that do not have a baseload need" due to high costs of DER solutions to meet baseload needs.[20]

7.2. Forecast Uncertainty Metric

Higher tiered projects under the Forecast Uncertainty Metric are characterized by:

- Available Supervisory Control and Data Acquisition (SCADA) data recordings
- Nearer term need (e.g., 2022 versus 2024)
- Higher number of customers causing need
- Judgement based on engineering knowledge of the area

[20] Public Independent Evaluator Report, Advice Letter 5259-E, Sedway Consulting, Inc., p. 7, March 26, 2018.

The forecast uncertainty metric is intended to give a relative indication of the certainty of the forecast grid need. The availability of SCADA data provides more certainty on the forecast and is given the most weight for this metric. A higher number of customers causing the need is assumed to decrease the variance in the dependence of the need per customer. Furthermore, engineering judgement from PG&E's distribution planners is also considered. The planners may consider the status of development milestones for large commercial, industrial and agricultural customers seeking new service or expansion of service. PG&E's distribution planners may also consider whether load forecast is particularly uncertain due to agriculture pumping load which is dependent on water availability and temperature/weather patterns.

7.3. Market Assessment Metric

Higher tiered projects under the Market Assessment Metric are characterized by:

- Only Day Ahead, rather than Real Time, operational requirements
- Low number of electric facilities experiencing grid needs in a specific location
- Shorter duration of needs
- Fewer number of days needed per year
- Lower ratio of overload (lower penetration required)
- Judgement based on experience with pilots

The Market Assessment metric is intended to give a relative indication of how likely DER resources can be sourced that will successfully meet the DER distribution service requirements. For example, a location with multiple electric facilities experiencing grid needs may be more difficult to source DER solutions that are able to meet all the electric facility grid needs than a location with a single electric facility experiencing a grid need. In addition, a key learning from PG&E's DRP Demonstration Project C was that long duration needs with frequent calls (similar to baseload resources) are difficult to source. Operational requirements that require Real Time dispatch are less likely to be sourced via DERs versus operational requirements that only require Day Ahead dispatch. A high overload also indicates that a greater percentage of DER sourcing is needed.

7.4. Prioritization Metric Results

For ease of summarizing prioritization metric results, PG&E has developed a 4-tier system, where each tier represents PG&E's proposed priority ranking of those Candidate Deferral Opportunities likelihood of success for DER sourcing. The following table summarizes PG&E's proposed 4-tier system.

Table 11: PG&E's 4-Tier Prioritization System

Tier	Color Designation	Definition
1		Relatively High Ranking
2		Relatively Moderate Ranking
3		Relatively Low Ranking
4		Already Sourced Elsewhere

All ranking of projects is relative. For example, a higher tiered project does not indicate that the project will be cost effective, have a certain forecast, or have a robust market[21]. It only indicates the ranking of the Candidate Deferral Opportunity relative to other Candidate Deferral Opportunities.

A red ranking indicates that there is a "red flag" associated with the Candidate Deferral Opportunity. Below are a few examples of the red flags, among others:

- Market Assessment: A market assessment red flag for a candidate deferral opportunity could be in regard to a lengthy DER service duration requirement, such as a continuous 24 hours or baseload need. PG&E has obtained learnings from prior pilots that baseload requirements may be difficult to obtain cost-effectively from DERs. The Independent Evaluator reported "it may be best for PG&E to target circuit needs for future DRP RFOs that do not have a baseload need", due to high costs of DER solutions to meet baseload needs.[22]
- Forecast Certainty: Absence of SCADA data, which increases the forecast uncertainty that the peak demand will materialize. Another example is an in-service date of 2024 (greater than 5 years), which increases the forecast uncertainty and indicates the Candidate Deferral Opportunity may be more appropriately considered in future DDORs.

[21] For example, blue Candidate Deferral Opportunities are expected to be more cost effective than red Candidate Deferral Opportunities, but it does not indicate the Candidate Deferral Opportunity will be cost effective. Similarly, all the opportunities have some degree of forecast uncertainty. In contrast, a RAG (Red, Amber, Green) ranking would indicate an absolute ranking (e.g., a green ranking would indicate a certain forecast).

[22] Public Independent Evaluator Report, Advice Letter 5259-E, Sedway Consulting, Inc., p. 7, March 26, 2018.

- Cost Effectiveness: Another example of a red flag for cost effectiveness is a LNBA value in the $0-$50/kW-year range. These red flags indicate that it is not likely a DER deferral solution can successfully be sourced at this time, although these grid needs would be re-evaluated in the following year's GNA and DDOR.

The individual prioritization assessment for the ranking of each Candidate Deferral Opportunity is included in Appendix C.

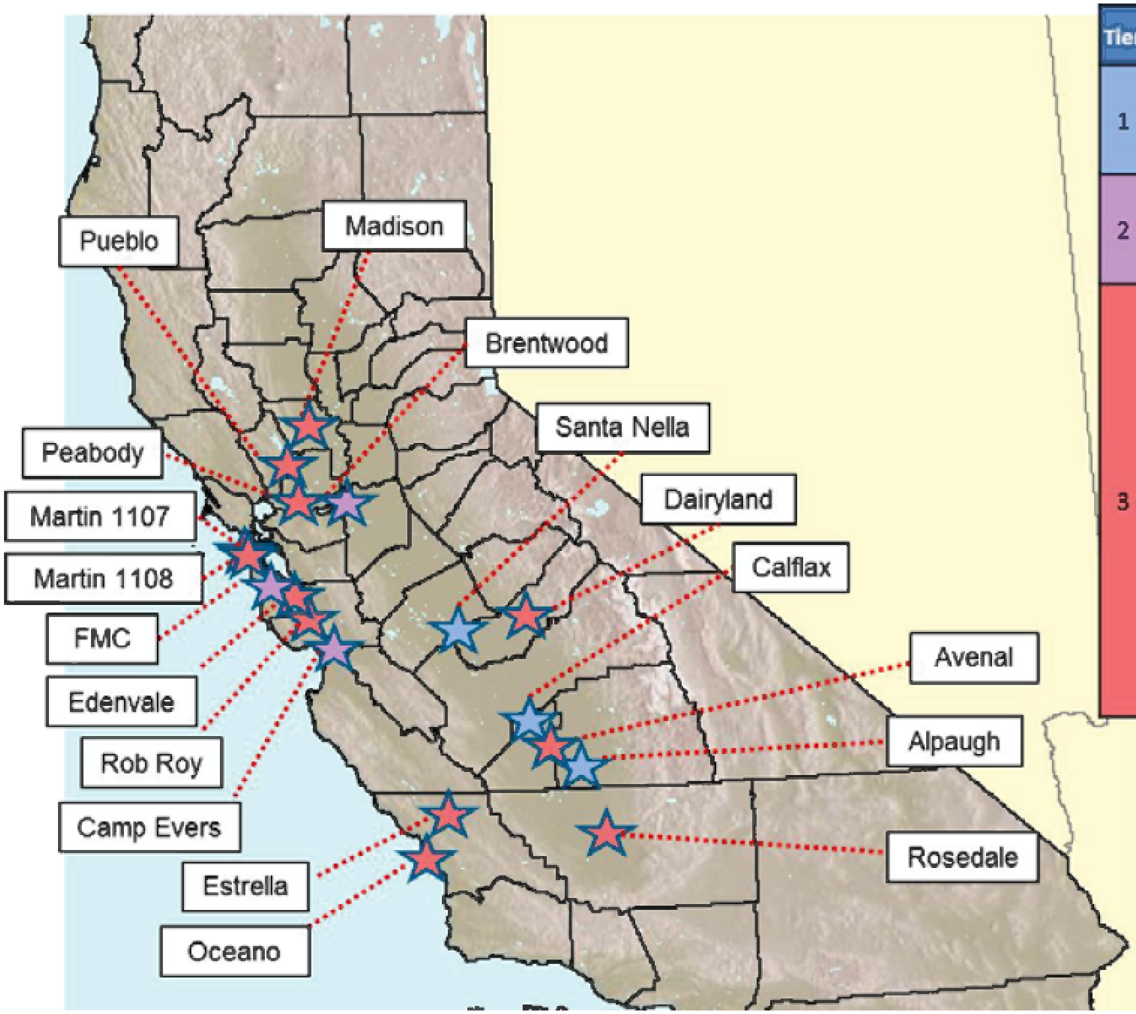
8. Candidate Deferral Opportunity Prioritization

PG&E's prioritization of its identified Candidate Deferral Opportunities is summarized in Table 12. Using PG&E's tier prioritization system, PG&E has identified approximately 88 MW of Candidate Deferral Opportunities for this DDOR, which are:

- Tier 1: Identified three Candidate Deferral Opportunities totaling approximately 18.5 MW. Tier 1 Candidate Deferral Opportunities are relatively more likely to be deferrable.
- Tier 2: Identified three Candidate Deferral Opportunities totaling approximately 2.9 MW. Tier 2 Candidate Deferral Opportunities have identified some red flags that indicate they are unlikely to be successfully deferred now. PG&E recommends not pursuing these Candidate Deferral Opportunities, but to closely monitor status and project conditions and re-evaluate for a future date.
- Tier 3: Identified twelve Candidate Deferral Opportunities totaling approximately 66.9 MW. Tier 3 Candidate Deferral Opportunities have multiple major red flags that have been identified and indicate it is not likely a DER deferral solution can successfully be sourced.

Table 12: Preliminary Prioritization Metrics and Rankings of Candidate Deferral Opportunities

Tier	Candidate Deferral Opportunities	In-Service Date	Deficiency (MW)	Prioritization Metrics		
				Cost Effectiveness	Forecast Certainty	Market Assessment
1	Alpaugh New Feeder	2022	4.4			
	Calflax Bank 2	2023	CC			
	Santa Nella New Bank & Feeder	2022	9.3			
2	Camp Evers 2107	2022	0.9			
	FMC 1102	2023	0.8			
	Brentwood 2105	2022	1.2			
3	Estrella Substation	2024	24.3			
	Pueblo Bank 3	2022	23.2			
	Oceano 1106	2022	1.2			
	Rosedale 2102	2022	1.8			
	Rob Roy 2105	2022	3.0			
	Peabody 2106	2022	CC			
	Madison 2101	2022	CC			
	Martin SF H 1108	2022	1.0			
	Martin SF H 1107	2022	1.8			
	Avenal 2101	2022	CC			
	Edenvale 2108	2022	1.5			
	Dairyland 1110 New Feeder	2022	4.5			



Tier	Candidate Deferral	In-Service Date	Deficiency (MW)
1	Alpaugh New Feeder	2022	4.4
	Calflax Bank 2	2023	
	Santa Nella New Bank & Feeder	2022	9.3
2	Camp Evers 2107	2022	0.9
	FMC 1102	2023	0.8
	Brentwood 2105	2022	1.2
3	Estrella Substation	2024	24.3
	Pueblo Bank 3	2022	23.2
	Oceano 1106	2022	1.2
	Rosedale 2102	2022	1.8
	Rob Roy 2105	2022	3.0
	Peabody 2106	2022	
	Madison 2101	2022	
	Martin SF H 1108	2022	1.0
	Martin SF H 1107	2022	1.8
	Avenal 2101	2022	
	Edenvale 2108	2022	1.5
	Dairyland 1110 New Feeder	2022	4.5

Figure 3: PG&E's 2019 Candidate Deferral Opportunity Locations

9. Contingency Plans

Electric distribution systems can change dynamically in terms of local area demand in response to agricultural water allocation and temperature sensitivity, economic drivers, and the unpredictability of large new customer load additions. When one of these drivers causes the load or near term forecast to exceed the local system capability, PG&E manages the load until capacity upgrades can be installed using field switching where possible, temporary re-rates on various pieces of equipment, and/or installation of temporary and mobile equipment.

Generally, these are the same contingency planning steps PG&E will use for contracted DER solutions that are not able to successfully mitigate the grid needs for the identified Candidate Deferral Opportunities. Specifically, PG&E has considered three different project stages where a DER solution can fail in being able to provide successful distribution services:

1. **DER Solicitation stage:** If no cost-effective or combination of cost-effective bids meet the grid need, or if there is a change in forecasted grid need date (e.g., accelerating the need for a solution sooner than originally planned), the contingency plan option is to either consider the deferral opportunity again in next year's DDOR or proceed with the planned "wires" project if the start date for the project is prior to next year's distribution resources planning process.
2. **DER Implementation stage:** If the contracted DER solution fails to meet its implementation milestones and is not expected to achieve operations by the identified grid need date, or if there is a change in forecasted grid need date (e.g., accelerating the need for a solution sooner than originally planned), the contingency plan options available during this stage depends upon when during the DER implementation stage it becomes known the DER solution will be not be available to meet the identified grid need date. If it is early in the implementation stage, it may be possible for another cost-effective or combination of cost-effective bids to be considered. If that is not the case, the contingency is to implement the planned wires project if possible. If it is later in the DER implementation stage, depending upon the loading and system conditions, a stop-gap wires solution including the various steps described above will be implemented.
3. **Commercial Operation stage:** If the contracted DER resource fails to meet performance requirements or simply fails while in service, PG&E will handle this situation in the same manner as with any other failed equipment. The immediate emergency response includes distribution operations personnel implementing load transfers based on current loading profiles, installation of mobile generation, and/or a plan to interrupt power for local customers as a last resort. The contingency plan beyond the initial 24 hours would consider area loading, expected duration of the DER resource failure, potential transfers that may be

available because of recent distribution infrastructure additions or improvements, re-rating of distribution facilities[23], including substation banks, and installation of temporary facilities such as a mobile transformer bank.

It is important to note that new customer load applications for demand in the 2-5 MW range are not uncommon. PG&E cannot predict with absolute certainty where or when large new customer load will happen. If an updated demand forecast is higher than what the DER solution can provide, PG&E would deploy the same contingency strategies identified previously in this section. PG&E also coordinates with customers in providing new service based on the size and timing of the load ramp up schedule.

As part of the ongoing evaluation and reform of the DIDF process, PG&E reports on the contingency spending for the most recent DIDF solicitations.[24] As the 2018 DIDF RFO is still ongoing, PG&E has continued its design and engineering of the Planned Investments for the Candidate Deferral Opportunities.[25] As of August 5, 2019, the contingency spend on the Candidate Deferral Opportunities is as follows:

- New Lammers Feeder: $1,425.63
- Huron Bank 1: $257,906.24
- Santa Nella Bank 1: $251,317.97

10. Recommendations and Next Steps

PG&E's recommendation is to pursue competitive solicitations for only the Tier 1 Candidate Deferral Opportunities (3 projects totaling 18.5 MW) now. PG&E recommends pursuing competitive solicitations for the Alpaugh New Feeder (4.4 MW) and the Calfax Bank 2 (4.8 MW) Candidate Deferral Opportunities. The Santa Nella Candidate Deferral Opportunity was included in PG&E's 2018 DDOR and was approved for solicitation[26]. Negotiations for the Santa Nella Candidate Deferral Opportunity are currently underway as of August 15, 2019. PG&E is recommending that the Santa Nella Candidate Deferral Opportunity be solicited again if current negotiations do not result in an executed and approved contract for DER deferral, as described in the Contingency Plan (Section 9). If current negotiations result in an executed and approved contract for DER deferral for Santa Nella, then PG&E does not recommend re-soliciting for the Santa Nella Candidate Deferral Opportunity.

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[23] The use of emergency ratings is unlikely to be a viable contingency plan for Candidate Deferral Opportunities with long duration needs due to the duration of the need exceeding the duration of the emergency rating.

[24] May 2019 ALJ Ruling, p. 13.

[25] PGE AL 5435-E, p. 16.

[26] PG&E AL 5435-E

PG&E does not recommend pursuing competitive solicitations for Tiers 2 and 3 at this time due to their low likelihood of achieving a successful outcome. However, PG&E does recommend closely monitoring the status and conditions of the Tier 2 projects for re-evaluation and consideration of competitive solicitations at a later date. Therefore, these projects are not considered for competitive solicitation in this DDOR.

PG&E will present the Candidate Deferral Opportunities and preliminary prioritization metrics to the DPAG by September 20, 2019. The following section describes PG&E's proposed workplan for the DPAG.

10.1. Proposed Workplan for the Distribution Planning Advisory Group

In accordance with D.18-02-004 ordering paragraphs 2.t, 2.u, and 2.v, and the May 7, 2019 Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework Process, PG&E will proceed with the below work plan for the DPAG meetings:

- Sept 10: The IPE circulates preliminary analysis of PG&E's GNA and DDOR
- Sept 16: Joint IOUs to host DPAG Primer Webinar
- Sept 19: PG&E to host its DPAG meeting. The following is the meeting agenda as set by Energy Division staff in an August 14, 2019 electronic communication:
    - Planning assumptions and grid needs reported in the GNA
        - Review GNA data and discuss how the key GNA values were calculated
        - Overview of GNA results
        - What value determines whether a planned investment is necessary
    - Planned investments and candidate deferral opportunities reported in the DDOR
        - Overview of types of planned investments included in DDOR (and what types of distribution investments are in GRC but not included in DDOR)
        - Table that summarizes planned investments by type (in DDOR only) and capacity
    - Candidate deferral prioritization
        - Review the prioritization screens of the IOU's candidate deferral projects to discuss why investments were excluded
    - Underlying technical and operational requirements for the DER alternative.
    - Review criteria of potential projects for inclusion in solicitation to discuss whether DERs could fill the need at the cost of deferral
- Sept 23: Participants provide questions and comments to IOUs and IPE
- Oct 7-8: PG&E to host follow up DPAG meeting via Webinar
- Oct 21: IPE Final Report issued

Based on feedback from the DPAG and the IPE, PG&E will then submit its Final Candidate Deferral List via an Advice Letter by November 15, 2019.

10.2. Future DIDF Reform

To consider future reforms to the DIDF process, PG&E provides the following recommendations for future DIDF reform:[27]

- Overall, PG&E views the Distribution Investment Deferral Framework (DIDF) as successfully providing information about PG&E's distribution planning process and identifying opportunities for deferral by DERs.
- PG&E recommends that customer count information only be required for the Candidate Deferral Opportunities (rather than for all Planned Investments), as the purpose of this information is to evaluate the feasibility of DER deferral and it is a significant undertaking to provide this information for all Planned Investments.
- PG&E recommends that LNBA calculations only be required for the Candidate Deferral Opportunities (rather than for all Planned Investments), as the purpose of this information is to evaluate the feasibility of DER deferral and it is a significant undertaking to provide this information for all Planned Investments.
- PG&E recommends that the viability of DER projects that rely on additional revenue streams be further considered, especially if the DER project has not been studied for interconnection and requires charging (acts as a load) from the overloaded circuit.
- PG&E recommends that the regulatory process for the DIDF be streamlined, to allow for more time between when the Candidate Deferral Opportunities are finalized and when bids are due from developers, as well as allowing for the shortening of the timing screen, as proposed in PG&E's comments for DIDF Improvements.[28]
- PG&E recommends that line sections be excluded from future DIDF cycles, as assessing line section needs and documenting the line section Planned Investments requires extensive effort, while few, if any, are likely to be viable Candidate Deferral Opportunities due to the near-term identification of the need, the uncertainty of the long term forecast for line sections, the relatively smaller amount of customers for which to potentially market DERs, and the relatively smaller cost of the traditional mitigation.
- PG&E has worked with the other IOUs towards making the datasets provided in the 2019 GNA and DDOR filings common and comparable. For example, PG&E provided a table template to the other IOUs for review prior to filing. PG&E will

[27] May ALJ Ruling, p. 16.

[28] PG&E Opening Comments on ALJ Ruling Seeking to Improve the Distribution Investment Deferral Framework, March 2019, pp. 3-5.

review the other IOUs 2019 GNA and DDOR filings and identify what changes, if any, are necessary to achieve a common, comparable dataset for PG&E’s 2020 GNA and DDOR filing.

Appendix A Planned Investments

Planned Investment Name	Distribution Planning Region	Division	Project Type	Proposed Work	In-Service Date	Deferrable (Y/N)?	LNBA Value ($/kW-yr)	LNBA Value ($/Vpu-yr	Customer Count						GNA Facility Name	Distribution Service Required	Grid Need	Units (MW/Vpu)
									Residential	Commercial	Industrial	Agricultural	Other	Total				
Santa Nella New Bank & Feeder	Central Valley	Yosemite	Bank	New 30 MVA Bank and new feeder	2022	Y	$117		2,019	102	18	106	297	2,542	CANAL BANK 1	Capacity	0.66	MW
															CANAL BANK 2	Capacity	1.27	MW
															ORTIGA BANK 1	Capacity	1.93	MW
															CANAL 1103	Capacity	1.57	MW
															SANTA NELLA 1104	Capacity	0.24	MW
															ORTIGA 1106	Capacity	0.09	MW
Dairyland 1110 Feeder	Central Valley	Yosemite	Feeder	Install new feeder on Dairyland	2022	Y	$113		128	41	7	219	191	586	DAIRYLAND BANK 1	Capacity	1.35	MW
															DAIRYLAND 1109	Capacity	1.84	MW
Alpaugh New Feeder	Central Valley	Fresno	Feeder	Install new feeder at Alpaugh Substation	2022	Y	$91		1,306	55	7	33	80	1,481	CORCORAN BANK 3	Capacity	2.66	MW
															CORCORAN 1112	Capacity	1.02	MW
Calflax Bank 2	Central Valley	Fresno	Bank	Install Calflax Bank 2	2023	Y	$167		54	17	2	86	86	245	CALFLAX BANK 1	Capacity	CC	MW
Pueblo Bank 3	Bay Area	North Bay	Bank	Install 45 MVA bank	2022	Y	$28		8,624	482	136	353	507	10,102	Pueblo Bk 1	Reliability / Other	17.40	MW
Camp Evers 2107	Central Coast	Central Coast	Feeder	Install breaker and extend circuit	2022	Y	$218		5,675	522	77	5	181	6,460	Camp Evers 2106	Reliability / Other	0.87	MW
FMC 1102	Central Coast	San Jose	Feeder	Install breaker and extend circuit	2023	Y	$232		999	131	48	-	21	1,199	FMC 1101	Reliability / Other	0.79	MW
Brentwood 2105	Bay Area	Diablo	Line section	Install 2500' of cable in existing conduit	2022	Y	$59		2,276	241	76	80	245	2,918	Brentwood 2105	Reliability / Other	1.20	MW
Avenal 2101	Central Valley	Fresno	Line section	200' tie and switches	2022	Y	$6		1,661	192	44	37	61	1,995	Avenal 2101	Reliability / Other	CC	MW
Rosedale 2102	Central Valley	Kern	Line section	Install 1750' of cable in existing conduit	2022	Y	$24		957	249	127	-	60	1,393	Rosedale 2102	Reliability / Other	1.82	MW
Madison 2101	Northern	Sacramento	Line section	Install 900' tie and switch	2022	Y	$13		775	140	21	183	331	1,450	Madison 2101	Reliability / Other	CC	MW
Peabody 2106	Northern	Sacramento	Line section	Reconductor OHL and new UG	2022	Y	$8		2,704	50	9	1	96	2,860	Peabody 2106	Reliability / Other	CC	MW
Martin SF H 1107	Bay Area	San Francisco	Line section	Replace 250' UG cable	2022	Y	$5		6,655	372	37	-	50	7,114	Martin SF H 1107	Reliability / Other	1.68	MW

Planned Investment Name	Distribution Planning Region	Division	Project Type	Proposed Work	In-Service Date	Deferrable (Y/N)?	LNBA Value ($/kW-yr)	LNBA Value ($/Vpu-yr	Customer Count						GNA Facility Name	Distribution Service Required	Grid Need	Units (MW/Vpu)
									Residential	Commercial	Industrial	Agricultural	Other	Total				
Martin SF H 1108	Bay Area	San Francisco	Line section	Replace fuses with reclosers	2022	Y	$11		6,429	265	37	-	72	6,803	Martin SF H 1108	Reliability / Other	0.88	MW
Rob Roy 2105	Central Coast	Central Coast	Line section	Install 3000' new OH, switch, and recloser	2022	Y	$17		6,311	567	87	12	111	7,088	Rob Roy 2105	Reliability / Other	3.26	MW
Oceano 1106	Central Coast	Los Padres	Line section	Replace UG cable	2022	Y	$19		4,812	582	66	40	180	5,680	Oceano 1106	Reliability / Other	1.16	MW
Edenvale 2108	Central Coast	San Jose	Line section	Install SCADA MSO	2022	Y	$6		6,360	133	49	-	118	6,660	Edenvale 2108	Reliability / Other	1.66	MW
Estrella Substation	Central Coast	Los Padres	Substation	Construct Estrella Substation - 45 MVA transformer and fully populated switchgear enclosure	2024	Y	$558		1,887	291	62	266	321	2,827	SAN MIGUEL BANK 1	Capacity	1.68	MW
															TEMPLETON BANK 3	Capacity	0.12	MW
															PASO ROBLES 1104	Capacity	1.15	MW
															Cholame Between X14 and R96	Reliability / Other	1.2	MW
															Cholame Sub DA	Reliability / Other	11.8	MW
															Cholame Sub RT	Reliability / Other		
															L/S R78 - Templeton 2109	Reliability / Other	5.4	MW
Edes 1101 outlet	Bay Area	East Bay	Line section	Replace 800ft of UG cable	2019	N	$3		1,533	185	81	1	25	1,825	EDES 1101	Capacity	CC	MW
															EDES 1114	Capacity	CC	MW
Extend J 1116 to J 1104	Bay Area	East Bay	Line section	Extend mainline and add switches	2020	N	$65		7,035	397	78	-	96	7,606	Oakland J 1116	Reliability / Other	0.88	MW
Reinforce Oakland X 1107	Bay Area	East Bay	Line section	Reconductor Oakland X1107 to facilitate transfer of 1850 customers from Oakland X1115 to Oakland X1107	2020	N	$10		6,930	380	55	-	67	7,432	Oakland X 1115	Reliability / Other	1.57	MW
Kirker 2103-2108 Back-Tie	Bay Area	Diablo	Line section	1470' of cable in new trench, 900' of cable in existing conduit	2020	N	$55		5,368	391	139	7	107	6,012	Kirker 2103	Reliability / Other	1.78	MW
Ignacio 1101 Back-Tie	Bay Area	North Bay	Line section	Install sw and sw-int-sw, trench approximately 400', reconductor OH 850'	2020	N	$17		2,647	120	31	-	33	2,831	Ignacio 1101	Reliability / Other	2.90	MW
Install Lakewood Bk 7	Bay Area	Diablo	Bank	Install 30 MVA 12/21 kV step-down TX	2019	N	$20		5,177	359	137	-	115	5,788	Lakewood Bk 5	Reliability / Other	16.90	MW

Planned Investment Name	Distribution Planning Region	Division	Project Type	Proposed Work	In-Service Date	Deferrable (Y/N)?	LNBA Value ($/kW-yr)	LNBA Value ($/Vpu-yr)	Customer Count						GNA Facility Name	Distribution Service Required	Grid Need	Units (MW/Vpu)
									Residential	Commercial	Industrial	Agricultural	Other	Total				
Highway 1107 - Install new feeder	Bay Area	North Bay	Feeder	Add new feeder breaker on Highway bank 1 and run circuit in field	2020	N	$608		1,006	244	139	7	104	1,500	HIGHWAY 1102	Capacity	0.40	MW
Install Rossmoor 1109	Bay Area	Diablo	Feeder	Install breaker, extend circuit	2020	N	$44		9,004	648	142	2	403	10,199	Moraga Bk 5	Reliability / Other	13.40	MW
Install Brentwood 2104	Bay Area	Diablo	Feeder	Install breaker and extend circuit	2021	N	$52		2,960	325	53	78	750	4,166	Contra Costa 2113	Reliability / Other	1.48	MW
															Brentwood 2112	Reliability / Other	1.45	MW
Oceanwide Center SF New Feeder Mission X 1127	Bay Area	San Francisco	Feeder	Install Breaker	2020	N	$62		1,546	129	91	-	27	1,793	EMBARCADERO (SF Z) 1119	Capacity	CC	MW
Install New Feeder Mission (SF X) 1129	Bay Area	San Francisco	Feeder	extend the 12 kV Bus and extend the feeder by installing 750CU primary UG cable	2021	N	$938		1,544	447	135	1	52	2,179	POTRERO (SF A) 1115	Capacity	CC	MW
Reconductor mainline	Bay Area	San Francisco	Line section	Replace cable	2021	N	$70		6,307	358	96	-	115	6,876	Mission SF X 1113	Reliability / Other	1.06	MW
Salinas 1102 - Install regulator and recloser	Central Coast	Central Coast	Line section	Replace overloaded Booster B24 with a 300A closed delta reg	2021	N	$4		6,725	166	78	8	79	7,056	Salinas 1102	Reliability / Other	CC	MW
SOLEDAD 2101 Transfer AG PROC NB LD IN GONZALES	Central Coast	Central Coast	Line section	reconductoring of about 7600ft of OH conductor and installation of 3 closed delta regulator units.	2019	N	$9		677	124	24	157	30	1,012	Gonzales Bk 4	Capacity	CC	MW
Los Ositos 2103 extension	Central Coast	Central Coast	Line section	primary overhead conductor 3,711ft, reconductor 2,187ft, cut over 17 total transformers from 12 to 21kV	2020	N	$32		3,167	238	60	39	208	3,712	Los Ositos 2101	Capacity	2.10	MW
East Grand 1116 & 1117 Feeders	Central Coast	Peninsula	Feeder	Install circuit breakers in Existing Switchgear Cells	2020	N	$9		2,742	708	275	-	205	3,930	EAST GRAND BANK 5	Capacity	1.93	MW
															EAST GRAND 1109	Capacity	3.02	MW
															EAST GRAND 1113	Capacity	13.52	MW
Fallon Rd Cable Upgrade	Central Coast	Central Coast	Line section	Hollister 2104 - Replace 170' of UG cable	2021	N	$9		1,230	427	119	119	291	2,186	HOLLISTER 2104	Capacity	0.52	MW
Install new Almaden circuit	Central Coast	San Jose	Feeder	Install 1950' of new UG, reconductor 1370' OH	2020	N	$43		2,659	84	60	-	59	2,862	ALMADEN 1111	Capacity	0.51	MW
															HICKS 1110	Capacity	1.66	MW

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									Residential	Commercial	Industrial	Agricultural	Other	Total				
EXTEND NORTECH 2109 TO SERVE KLA	Central Coast	San Jose	Line section	Intall 1,300 ft in existing 6" conduit and install 3 UG switches	2020	N	$16		3	22	30	1	14	70	NORTECH 2109	Capacity	CC	MW
Reconductor Gabilan 1101	Central Coast	Central Coast	Line section	Reconductor 2600ft OH	2019	N	$5		2,061	103	25	66	124	2,379	Gabilan 1101	Capacity	CC	MW
OFFLOAD 2MW FROM ATASCADERO 1103 TO 1102	Central Coast	Los Padres	Substation	installing SWs and trench 900 ft and install cable	2020	N	$16		3,640	216	18	49	276	4,199	ATASCADERO 1103	Capacity	1.60	MW
SOUTH ZABALA RD RECONDUCTOR	Central Coast	Central Coast	Line Section	Reconductor 3264' OH, install reg and cap bank	2020	N	$5		91	26	-	139	40	296	SPENCE 1102	Capacity	CC	MW
															SPENCE 1102	Voltage	CC	Vpu
															Gabilan 1101	Capacity	CC	MW
Reconductor Alisal Rd – NB Related – Spence 1121	Central Coast	Central Coast	Line section	Reconductor 3800' of OH	2020	N	$6		32	25	5	49	2	113	Spence 1105	Capacity	CC	MW
Reconductor Alisal Rd II – NB Related – Gabilan 1101	Central Coast	Central Coast	Line section	Reconductor 11000' of OH	2020	N	$109		2,061	103	25	66	124	2,379	Gabilan 1101	Capacity	CC	MW
Reconductor Tap-Line Off Spence Rd	Central Coast	Central Coast	Line section	Reconductor 1000' of OH	2020	N	$1		90	28	7	119	45	289	Spence 1103	Capacity	CC	MW
Install mainline backtie for Marian Medical Center	Central Coast	Los Padres	Line section	Install 333' 600Al EPR cable in existing 6" conduit. Trench and install 992' of 600Al EPR cable	2020	N	$18		2,958	434	106	14	114	3,626	Santa Maria 1112	Reliability / Other	CC	MW
Reconductor Tap-Line off Old Stage Rd	Central Coast	Central Coast	Line section	Reconductor 2150' of OH	2020	N	$45		2,061	103	25	66	124	2,379	Gabilan 1101	Capacity	CC	MW
Newark 2105 switch	Central Coast	Mission	Line Section	Replace OH switch	2020	N	$1		303	372	285	1	85	1,046	NEWARK 2105	Capacity	2.41	MW
Dumbarton 2111 regulator	Central Coast	Mission	Line Section	Add voltage regulator	2020	N		$0.10	1,381	140	93	-	905	2,519	DUMBARTON SUB 2111	Voltage	0.90	Vpu
Dumbarton 1109 switch	Central Coast	Mission	Line Section	Replace sw 6493 with 900A switch	2020	N	$0		2,797	229	129	-	191	3,346	DUMBARTON SUB 1109	Capacity	3.71	MW
Newark 1106 switch	Central Coast	Mission	Line Section	Replace switch	2020	N	$1		3,197	126	46	-	37	3,406	NEWARK 1106	Capacity	2.42	MW
Dumbarton 1107 Reconductor	Central Coast	Mission	Line Section	Reconductor OH line	2020	N	$4		4,662	404	93	-	94	5,253	DUMBARTON SUB 1107	Capacity	1.46	MW
Jarvis Sub - install bank and feeders	Central Coast	Mission	Feeder	Replace bank with 45 MVA TX and install new	2020	N	$299		5,798	187	40	1	315	6,341	Jarvis 1105	Reliability / Other	0.50	MW

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									Residential	Commercial	Industrial	Agricultural	Other	Total				
				circuit and exted 10,300 feet											Jarvis 1111	Reliability / Other	0.57	MW
															Jarvis 1112	Reliability / Other	1.65	MW
Install Santa Teresa Sub	Central Coast	San Jose	Substation	Install 45 MVA bank and two feeders with new UG cable to data centers	2021	N	$40		10,418	426	194	43	850	11,931	EDENVALE BANK 2	Capacity	CC	MW
															EDENVALE BANK 3	Capacity	CC	MW
															EDENVALE BANK 4	Capacity	CC	MW
															EDENVALE 2107	Capacity	CC	MW
															EDENVALE 2111	Capacity	CC	MW
Monterey Sub - Replace 4 kV bank with 21 kV Bk	Central Coast	Central Coast	Bank	Intall 30 MVA bank and circuits	2020	N	$56		5,356	801	249	11	119	6,536	Del Monte 2104	Reliability / Other	1.01	MW
															Del Monte 2105	Reliability / Other	7.62	MW
MESA 1104 FEEDER - PHASE 1	Central Coast	Los Padres	Feeder	4000' of new OH conductor; 2840' new UG cable	2019	N	$114		655	143	30	124	234	1,186	SANTA MARIA 1109	Capacity	CC	MW
Install Soledad Bk 7	Central Coast	Central Coast	Bank	Install 45 MVA bank and two circuit breakers	2020	N	$36		2,228	216	98	277	399	3,218	Soledad Bk 3	Reliability / Other	CC	MW
Install Dolan Rd Bk 2	Central Coast	Central Coast	Bank	Install 30 MVA bank and one new circuit breaker	2021	N	$160		3,252	429	94	226	74	4,075	Catroville Bank 1	Capacity	3.58	MW
															Dolan Rd Bk 1	Capacity	0.75	MW
															CASTROVILLE 2103	Voltage	0.97	Vpu
Install Vasona 1106	Central Coast	De Anza	Feeder	Install breaker in switchgear, extend feeder overhead	2020	N	$152		2,892	478	118	4	95	3,587	Los Gatos Bk 1	Capacity	1.83	MW
Replace Gonzales Bk 3	Central Coast	Central Coast	Bank	Replace w/ 30 MVA and install switchgear	2021	N	$56		1,659	119	48	57	21	1,904	Gonzales Bk 3	Capacity	CC	MW
															Gonzales Bk 4	Capacity	CC	MW
Carmel Valley_TBD_1	Central Coast	Central Coast	Line section	Otter 1102 - Install 100A SCADA reg	2021	N		$0.89	372	124	27	4	24	551	OTTER 1102	Voltage	0.99	Vpu
San Jose Station B1116, install 300A SCADA regulator	Central Coast	San Jose	Line Section	San Jose Station B1116, install 300A SCADA regulator	2021	N		$0.84	1,634	134	49	1	64	1,882	SAN JOSE B 1116	Voltage	0.99	Vpu

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									Residential	Commercial	Industrial	Agricultural	Other	Total				
Swift 2110, install 300A SCADA regulator	Central Coast	San Jose	Line Section	Swift 2110, install 300A SCADA regulator	2019	N		$0.61	2,031	103	46	7	118	2,305	SWIFT 2110	Voltage	0.98	Vpu
Camphora 1101 - Reconductor	Central Coast	Central Coast	Line Section	Reconductor 200ft of mainline to 715Al	2021	N	$18		114	57	11	146	29	357	CAMPHORA 1101	Capacity	CC	MW
Install switches	Central Coast	Mission	Line section	Install underground switches	2021	N	$55		5,878	315	67	-	125	6,385	San Leandro U 1107	Reliability / Other	0.41	MW
Install tie	Central Coast	Peninsula	Line section	Install backtie	2021	N	$9		-	12	16	-	7	35	East Grand 1106	Reliability / Other	CC	MW
Hollister 2101 - Install line Regulator	Central Coast	Central Coast	Line Section	Install 1200kVAR SCADA VAR control cap bank	2021	N		$0.36	352	130	30	116	145	773	HOLLISTER 2102	Voltage	0.99	Vpu
Hollister 2104 - Install SCADA line Regulator	Central Coast	Central Coast	Line Section	Install 300A SCADA Line Reg	2021	N		$1.25	1,230	427	119	119	291	2,186	HOLLISTER 2104	Voltage	0.99	Vpu
Cabrillo 1104 - Install SCADA VAR-Control Cap Bank	Central Coast	Los Padres	Line Section	Install 1200kVAR SCADA VAR-Control Cap Bank	2019	N		$0.12	1,206	65	17	120	83	1,491	CABRILLO 1104	Voltage	0.95	Vpu
Purisima 1101 - Capacitor Bank Replacement	Central Coast	Los Padres	Line Section	Replace existing 900kVAr Cap Bank (C744) with 1200kVAR SCADA VAR controlled.	2019	N		$0.38	2,113	145	26	50	52	2,386	PURISIMA SUB 1101	Voltage	CC	Vpu
Stelling 1110 Regulator	Central Coast	De Anza	Line Section	Install 300A regulator	2021	N		$0.89	3,460	254	44	4	41	3,803	STELLING 1110	Voltage	0.99	Vpu
Cayucos 1102 capacitor	Central Coast	Los Padres	Line Section	Install 1200 kVAR SCADA cap bank	2021	N		$0.24	3,733	157	19	41	101	4,051	CAYUCOS 1102	Voltage	CC	Vpu
Oceano 1105 - Install 200A SCADA Line Reg	Central Coast	Los Padres	Line Section	Install 200A SCADA Line Reg	2019	N	$146		5,560	581	137	9	192	6,479	OCEANO 1105	Capacity	0.09	MW
Templeton 2109 regulator	Central Coast	Los Padres	Line Section	Install 150 A line reg	2021	N		$0.84	2,879	223	39	249	294	3,684	TEMPLETON 2109	Voltage	0.99	Vpu
Templeton 2112 Regulator	Central Coast	Los Padres	Line Section	Install line reg	2021	N		$0.84	545	282	145	57	102	1,131	TEMPLETON 2112	Voltage	0.99	Vpu
Salinas_TBD_3	Central Coast	Central Coast	Line Section	Install 1200kVAr cap bank	2021	N		$0.62	165	90	29	3	41	328	SALINAS 1108	Voltage	CC	Vpu
Salinas_TBD_4	Central Coast	Central Coast	Line Section	Install 1200kVAr Cap bank and 300A line reg	2021	N		$0.43	90	28	7	119	45	289	SPENCE 1103	Voltage	CC	Vpu
Salinas_TBD_5	Central Coast	Central Coast	Line Section	Install 1200kVAr cap bank	2021	N		$0.36	194	105	17	142	1	459	SPENCE 1104	Voltage	CC	Vpu
Sisquoc 1102 - Install 2 Line Regs and a SCADA VAR control Cap Bank	Central Coast	Los Padres	Line Section	Install 2 300A SCADA Line Regs and 1200kVAR SCADA VAR control Cap Bank	2019	N		$1.05	252	87	21	165	114	639	SISQUOC 1102	Voltage	0.97	Vpu

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									Residential	Commercial	Industrial	Agricultural	Other	Total				
Foothill 1102 - Install 300A SCADA Line Reg	Central Coast	Los Padres	Line Section	Install 300A SCADA Line Reg	2021	N		$0.63	3,693	182	99	8	93	4,075	FOOTHILL 1102	Voltage	0.98	Vpu
Green Valley 2101 - Install SCADA VAR-Control Cap Bank	Central Coast	Central Coast	Line Section	Install 1800kVar cap bank	2021	N		$0.36	2,596	266	34	392	119	3,407	GREEN VALLEY 2101	Voltage	0.99	Vpu
CLAY 1103-RECOND BV CASINO (REVISED)	Central Valley	Stockton	Line Section	3320FT. Reconductoring OH, 2 OH Capactior Banks, 3 OH Regulators,	2021	N	$57		1,102	135	26	23	225	1,511	CLAY 1103	Capacity	CC	MW
INSTALL STOREY 1103 CIRCUIT (aka 31095122)	Central Valley	Yosemite	Feeder	25000 OH Reconductor	2021	N	$2,267		1,388	203	66	56	165	1,878	STOREY 1104	Capacity	0.11	MW
Lammers 1108	Central Valley	Stockton	Feeder	Install circuit breaker in existing switchgear and extend circuit	2021	N	$120		110	68	22	23	64	287	LAMMERS 1101	Capacity	CC	MW
McFarland 1101 reconductor	Central Valley	Kern	Line section	RECONDUCTOR 10,560 ft of overhead conductor. Work proposed to relieve the overload will also serve to stablish a back-tie between McFarland 1104 and McFarland 1101	2019	N	$21		1,703	179	31	43	69	2,025	MC FARLAND BANK 1	Capacity	0.33	MW
															MC FARLAND 1101	Capacity	1.11	MW
San Bernard 1101 - Granite Construction New business	Central Valley	Kern	Line Section	5280FT OF New OH Conductor, 2 OH Capactior Banks, 3 OH Regulators,	2020	N	$26		10	10	4	71	52	147	SAN BERNARD 1101	Capacity	CC	MW
California 1111 Recond Orange Ave	Central Valley	Fresno	Line section	Reconductor 2850ft of parallel 2Cu and 2/0Cu with 715Al.	2020	N	$506		731	274	182	74	89	1,350	MALAGA BANK 2	Capacity	0.05	MW
Bonita 1101 Reconductor 8000' 2 Cu	Central Valley	Yosemite	Line section	8000 ft OH Reconductor, 1 OH Switches, 3 OH Regulators,	2021	N	$42		211	38	6	124	169	548	BONITA 1101	Capacity	1.05	MW
Dinuba 1102 - reconductor 3800ft of 2 Cu	Central Valley	Fresno	Line section	3800FT. Reconductoring OH,	2019	N	$22		1,582	264	89	35	159	2,129	DINUBA 1102	Capacity	0.83	MW
California 1102 outlet reconductor	Central Valley	Fresno	Line section	Reconductor 3511ft of overhead line	2020	N	$9		558	158	125	13	50	904	CALIFORNIA AVE 1102	Capacity	2.01	MW
Avena 4KV cutover	Central Valley	Stockton	Line section	Replace 46 transformers and convert circuit voltage from 4 kV to 17 kV	2020	N	$237		684	109	16	323	328	1,460	AVENA BANK 1	Capacity	0.97	MW
Install new feeder Weber 1111	Central Valley	Stockton	Feeder	Install breaker in existing switchgear, extend circuit approx 1.75 miles	2019	N	$20		112	18	30	-	56	216	WEBER BANK 3	Capacity	CC	MW
															WEBER 1101	Capacity	CC	MW
															WEBER 1102	Capacity	CC	MW
															WEBER 1103	Capacity	CC	MW

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									Residential	Commercial	Industrial	Agricultural	Other	Total				
															WEBER 1108	Capacity	CC	MW
Install Rainbow 1103	Central Valley	Fresno	Feeder	Install a new circuit breaker on Rainbow BK1. Install 1,500 feet of new OH line and new line equipment.	2020	N	$201		1,303	118	14	364	390	2,189	SANGER BANK 1	Capacity	0.13	MW
															MC CALL 1101	Capacity	0.50	MW
MANTECA FLISR RESTORE AFTER XFERS	Central Valley	Stockton	Line section	Project proposes to iPstall two reclosers, two 900A swtiches and upgrade one regulator	2019	N	$2		5,481	424	168	2	468	6,543	MANTECA BANK 8	Capacity	6.21	MW
															VIERRA BANK 1	Capacity	1.17	MW
															VIERRA 1701	Capacity	2.11	MW
Tracy 4kv cut over	Central Valley	Stockton	Line section	3.7 MW of voltage conversion from 4 kV to 12 kV and install two switches	2021	N	$104		799	90	68	7	48	1,012	TRACY BANK 1	Capacity	1.31	MW
															TRACY 1102	Capacity	0.48	MW
Kern Oil 1108 Amazon Dist Center	Central Valley	Kern	Feeder	1100FT. Reconductoring OH, 150FT of OH Double Circuit, 1 OH Switches, 1 OH Capactior Banks,	2020	N	$5		2,395	136	64	-	77	2,672	KERN OIL 1108	Capacity	CC	MW
Harmonic Filter for Tesla Charging	Central Valley	Fresno	Line Section	200FT of UG Cable with Trench,	2019	N		$0.96	15	33	25	62	72	207	COALINGA NO 2 1107	Voltage	CC	Vpu
Dairyland 1105 Reconductoring	Central Valley	Yosemite	Line section	2716FT. Reconductoring OH, 1 OH Switches, 3 OH Regulators,	2019	N	$37		51	11	3	179	74	318	DAIRYLAND 1105	Capacity	CC	MW
Dairyland 1109 Reconductoring PH II	Central Valley	Yosemite	Line section	8170FT. Reconductoring OH, 4000FT OF New OH Conductor, 3 OH Switches, 1 OH Capactior Banks, 3 OH Regulators,	2019	N	$28		128	41	7	219	191	586	DAIRYLAND 1109	Capacity	2.55	MW
Kern Oil 1109 Replace Switch	Central Valley	Kern	Line section	1 OH Switches,	2020	N	$3		1,617	171	84	-	24	1,896	KERN OIL 1109	Capacity	CC	MW
Chowchilla 1102 Voltage Correction	Central Valley	Yosemite	Line section	2 cap banks	2019	N		$0.19	913	57	47	27	74	1,118	CHOWCHILLA 1102	Voltage	1.04	Vpu
Chowchilla 1103 install recloser	Central Valley	Yosemite	Line section	Install 1 recloser	2020	N	$28		1,082	69	18	75	134	1,378	LE GRAND 1104	Capacity	CC	MW
															CHOWCHILLA 1103	Voltage	CC	Vpu
Smyrna 1104 Low Voltage	Central Valley	Kern	Line section	1 OH Capactior Banks,	2019	N		$0.11	9	6	1	42	17	75	SMYRNA 1104	Voltage	CC	Vpu
Old River 1104 - Reconductoring OH	Central Valley	Kern	Line section	Reconductor 2400' of 4Cu with 397AL.	2020	N	$38		413	84	22	108	153	780	OLD RIVER 1104	Capacity	0.35	MW

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Kingsburg 1113 Primary low voltage & Reconductor	Central Valley	Fresno	Line section	3900FT. Reconductoring OH, 1 OH Capactior Banks, 6 OH Regulators,	2019	N	$115		300	40	19	222	209	790	KINGSBURG 1113	Capacity	CC	MW
West Fresno 1105 Low Voltage and PF	Central Valley	Fresno	Line section	3 OH Regulators,	2021	N		$0.89	729	143	19	2	53	946	WEST FRESNO 1105	Voltage	CC	Vpu
Lockeford 2102 Voltage Correction	Central Valley	Stockton	Line section	1 OH Capactior Banks, 3 OH Regulators,	2019	N		$1.07	1,513	233	38	441	393	2,618	LOCKEFORD SUB 2102	Voltage	0.99	Vpu
Linden 1104 Voltage Correction	Central Valley	Stockton	Line Section	3 OH Regulators,	2019	N		$1.14	414	41	5	112	118	690	LINDEN 1104	Voltage	0.98	Vpu
Install tie	Central Valley	Fresno	Line section	Install 2000' OH tie	2020	N	$15		1,266	64	12	336	354	2,032	Kingsburg 1116	Reliability / Other	1.30	MW
Corral 1101 Voltage Correction	Central Valley	Stockton	Line Section	1 OH Switches, 2 OH Capactior Banks,	2020	N		$0.59	1,506	153	23	120	253	2,055	CORRAL 1101	Voltage	0.99	Vpu
Weber 1113 - replace 5500ft of 4/0AL with 500CU	Central Valley	Stockton	Line section	5500FT UG CABLE W/OUT Trench,	2020	N	$3		112	18	30	-	56	216	WEBER 1101 WEBER 1108	Capacity Capacity	CC CC	MW MW
DINUBA 1103 - 2020 INSTALL NEW FEEDER	Central Valley	Fresno	Feeder	6600FT. Reconductoring OH, 1000FT of OH Double Circuit, 1000FT of UG Cable with Trench,	2019	N	$251		1,702	101	23	188	192	2,206	DINUBA 1105	Capacity	0.37	MW
COTTLE 1701 PRIMARY LOW VOLTAGE SUP.	Central Valley	Yosemite	Line section	1 OH Capactior Banks, 6 OH Regulators,	2020	N		$1.20	2,494	181	25	393	169	3,262	COTTLE 1701	Voltage	0.97	Vpu
Ortiga 1105 Reconductor Project	Central Valley	Yosemite	Line section	13193FT. Reconductoring OH,	2019	N	$56		1,325	108	26	25	76	1,560	ORTIGA 1105	Capacity	1.12	MW
EL NIDO 1106 - INSTALL NEW FEEDER	Central Valley	Yosemite	Feeder	50000FT. Reconductoring OH, 14000FT OF New OH Conductor, 5800FT of OH Double Circuit, 5800FT of UG Cable with Trench, 6 OH Switches, 1 OH Capactior Banks, 6 OH Regulators,	2019	N	$1,533		185	56	10	149	179	579	SANTA RITA 1102	Capacity	0.52	MW
STOREY 1111 & 1104 OL AND VOLTAGE CORR	Central Valley	Yosemite	Line section	3610FT. Reconductoring OH, 1 OH Switches, 3 OH Regulators,	2019	N	$185		2,612	106	40	2	102	2,862	STOREY 1111	Capacity	0.33	MW
CASSIDY 2108 12/21KV CUTOVER PH3 OL AUTO	Central Valley	Yosemite	Line section	65FT. Reconductoring OH, 65FT OF New OH Conductor, 3 Step downs, 7.176MW Cut-over (12-21, 4-12, 4-21, 4-17),	2019	N	$166		1,453	187	31	83	181	1,935	CASSIDY 2107 CASSIDY 2107	Capacity Capacity	1.16 1.16	MW MW
Herdlyn 1103 Voltage Correction	Central Valley	Stockton	Line section	3 OH Regulators,	2019	N		$0.83	110	65	5	126	96	402	HERDLYN 1103	Voltage	0.98	Vpu

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West Fresno 1110 Outlet Reconductoring	Central Valley	Fresno	Line section	650FT UG CABLE W/OUT Trench,	2019	N	$2		298	63	31	12	21	425	WEST FRESNO 1110	Capacity	CC	MW
															WEST FRESNO 1110	Capacity	CC	MW
Tulare Lake 1106 reconductor main line	Central Valley	Fresno	Line section	18500FT. Reconductoring OH,	2020	N	$111		23	24	4	70	29	150	TULARE LAKE 1106	Capacity	CC	MW
															TULARE LAKE 1106	Capacity	CC	MW
Ortiga 1106. replace OL KPF Switch	Central Valley	Yosemite	Line section	2 OH Switches,	2019	N	$2		754	50	20	69	280	1,173	ORTIGA 1106	Capacity	CC	MW
Tulare Lake 1108 create new tie line to Twissleman 1102 to offload 4cu main line.	Central Valley	Fresno	Feeder	22700FT. Reconductoring OH, 8500FT OF New OH Conductor, 1 OH Capactior Banks, 6 OH Regulators,	2020	N	$265		5	23	4	64	10	106	TULARE LAKE 1108	Capacity	0.77	MW
															TULARE LAKE 1108	Capacity	0.30	MW
Stockdale OL Switches	Central Valley	Kern	Line section	2 OH Switches,	2019	N	$2		3,834	97	46	46	222	4,245	STOCKDALE 2112	Capacity	1.66	MW
San Bernard BK 1 OL Relief	Central Valley	Kern	Bank	7696FT. Reconductoring OH, 3 OH Regulators,	2020	N	$113		19	8	-	51	40	118	TEJON 1105 (formerly 1104)	Capacity	CC	MW
Semitropic 1108- Low voltage Correction	Central Valley	Kern	Bank	Reconductoring OH, UG Cable, Switches, Capactior Banks, Regulators	2020	N		$9.46	30	9	2	64	31	136	GANSO 1103	Voltage	CC	Vpu
Install Cottle Bk 3	Central Valley	Yosemite	Bank	Install bank, breaker, and reconfigure circuits	2019	N	$17		2,937	224	28	456	192	3,837	Cottle Bk 1	Reliability / Other	30.60	MW
															COTTLE 1703	Capacity	2.42	MW
Rio Bravo 1104 Feeder	Central Valley	Kern	Feeder	install new feeder 3700 feet of 1100Al, 2-7.5 MVA 12/21KV Auto-txs, 1-3.6 MVA Auto-tx, 15,824 feet of 715Al underbuilt, 2 switches, 2 recloser, Relocate Auto-transforme	2019	N	$33		1,684	38	60	25	87	1,894	7TH STANDARD BANK 1	Capacity	5.06	MW
															7TH STANDARD 2102	Capacity	5.59	MW
Reconductor Shepherd 2111	Central Valley	Fresno	Line section	reconductor 26,790ft with 715Al.	2019	N	$26		772	77	22	26	185	1,082	Shepherd 2111	Reliability / Other	CC	MW
Oro Loma 1118 Horizon Nut Reconductoring	Central Valley	Yosemite	Line section	47300FT. Reconductoring OH,	2020	N	$60		19	17	3	52	83	174	ORO LOMA 1118	Capacity	CC	MW
El Nido Bank 1 Replacement	Central Valley	Yosemite	Bank	Replace El Nido Bank 1 with a 30 MVA	2020	N	$115		176	47	8	327	340	898	EL NIDO BANK 1	Capacity	1.69	MW
Install Airways 1104 and Airways 1107 Feeders	Central Valley	Fresno	Feeder	Ins 17,900 feet of 715 Al OH and 5,000 feet of 1100 Al UG in mostly existing conduit	2019	N	$38		1,693	41	3	2	123	1,862	AIRWAYS BANK 1	Capacity	5.19	MW
															AIRWAYS 1101	Capacity	8.65	MW
															AIRWAYS 1105	Capacity	0.26	MW

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									Residential	Commercial	Industrial	Agricultural	Other	Total				
															CLOVIS 1108	Capacity	1.50	MW
Dinuba 1103	Central Valley	Fresno	Feeder	Install breaker, reconductor 6600', Install 1000' new overhead	2020	N	$85		1,582	264	89	35	159	2,129	DINUBA 1102	Capacity	0.41	MW
															DINUBA 1104	Capacity	0.99	MW
															DINUBA 1105	Capacity	0.37	MW
Sanger 1118 Bus to PCB connection	Central Valley	Fresno	Substation	Replace 3/8" Cu tube connection with 500 Cu conductor	2020	N	$9		1,310	36	2	53	276	1,677	SANGER 1118	Capacity	CC	MW
Huron Bk 1	Central Valley	Fresno	Bank	Replace bank with 30 MVA	2021	N	$315		1,550	189	47	110	137	2,033	HURON BANK 1	Capacity	1.10	MW
El Nido 1106 Feeder	Central Valley	Yosemite	Feeder	Install El Nido 1106 in existing bay approx. reconductor 500ft and install 3 new OH switches	2020	N	$1		185	56	10	149	179	579	SANTA RITA BANK 1	Capacity	3.29	MW
															SANTA RITA 1102	Capacity	0.52	MW
Lakeview 1106 - Reconductor 5228ft of 4AR with 397Al . Install 100A regulattors. Install normal open switch for transfer.	Central Valley	Kern	Line section	5228FT. Reconductoring OH, 1 OH Switches, 3 OH Regulators,	2019	N	$65		14	16	12	54	62	158	LAKEVIEW 1106 (old 1103)	Capacity	CC	MW
Lakeview 1103 - install 300A regulator and relocate 150A regulator.	Central Valley	Kern	Line section	3 OH Regulators,	2020	N		$0.81	4	13	3	39	24	83	LAKEVIEW 1103	Voltage	CC	Vpu
Canal 1101 Reconductoring	Central Valley	Yosemite	Line section	10000FT. Reconductoring OH,	2019	N	$568		2,019	102	18	106	297	2,542	CANAL 1101	Capacity	0.08	MW
Canal 1103 Feeder OL	Central Valley	Yosemite	Feeder	13193FT. Reconductoring OH,	2019	N	$40		2,034	27	8	4	326	2,399	CANAL 1103	Capacity	1.57	MW
Chowchilla 1106 Voltage Correction	Central Valley	Yosemite	Line section	2 OH Capactior Banks,	2019	N		$0.17	130	34	11	136	121	432	CHOWCHILLA 1106	Voltage	1.03	Vpu
LoadSEER_CVR_Chowchilla_TBD1	Central Valley	Yosemite	Feeder	Reconductor approx 30,170ft OH line	2021	N	$106		121	31	6	179	186	523	EL NIDO 1104	Capacity	1.62	MW
Corcoran 1116 - reconductor 7200ft of 2 CU with 397AL	Central Valley	Fresno	Line section	7200FT. Reconductoring OH, 3 OH Regulators,	2021	N	$36		211	35	3	110	101	460	CORCORAN 1116	Capacity	1.08	MW
Cuyama 2102 - Install a 900KVAr Cap bank to correct PF and Voltage issues.	Central Valley	Kern	Line section	1 OH Capactior Banks,	2019	N		$0.18	37	23	1	22	33	116	CUYAMA 2102	Voltage	CC	Vpu

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Giffen 1102 - Reconductoring	Central Valley	Fresno	Line section	Reconductoring 1220FT of UG Cable with Trench	2019	N	$8		35	19	-	52	44	150	GIFFEN 1102	Capacity	CC	MW
Schindler 1110 - Install	Central Valley	Fresno	Line section	Install 8 OH Capactior Banks. Change all switched Capacitors banks to VAR controls	2019	N		$0.54	63	33	9	95	42	242	SCHINDLER 1110	Voltage	CC	Vpu
Schindler 1111 - Install new 300A regulator to remedy 116.1V low voltage.	Central Valley	Fresno	Line section	3 OH Regulators,	2019	N		$0.93	25	21	-	52	33	131	SCHINDLER 1111	Voltage	CC	Vpu
Gates 1102 Voltage Correction	Central Valley	Fresno	Feeder	6 OH Regulators,	2019	N		$5.98	13	13	-	42	77	145	GATES 1102	Voltage	CC	Vpu
Storey 1108 Voltage Correction	Central Valley	Yosemite	Line section	3 OH Regulators,	2019	N		$0.61	1,867	119	18	35	197	2,236	STOREY 1108	Voltage	1.02	Vpu
Install tie North Stockton 21 kV	Central Valley	Stockton	Line section	8200' of UG in new trench	2021	N	$20		2,763	49	36	-	338	3,186	Mosher 2108	Reliability / Other	4.90	MW
Guernsey 1103 OL Correction Project	Central Valley	Fresno	Line section	4800FT. Reconductoring OH, 2 OH Switches, 3 OH Regulators,	2019	N	$21		104	23	4	130	103	364	GUERNSEY 1102	Capacity	1.48	MW
Kerman 1104 - reconductor 6200ft of 267AL choker with 715AL	Central Valley	Fresno	Line section	Reconductor 6200 ft of OH	2019	N	$16		205	20	2	122	154	503	KERMAN 1104	Capacity	1.85	MW
Kerman 1102 - Install 900A overhead switch to correct overload	Central Valley	Fresno	Line section	1 OH Switches,	2019	N	$44		1,960	132	10	129	340	2,571	KERMAN 1102	Capacity	0.08	MW
Kingsburg 1113 Breaker loading reduction	Central Valley	Fresno	Feeder	38200FT. Reconductoring OH, 3200FT OF New OH Conductor, 4 OH Switches, 3 OH Regulators,	2019	N	$663		999	136	16	441	374	1,966	KINGSBURG 1111 (old 1114)	Capacity	0.76	MW
Weedpatch 1102 - replace switch and regulators	Central Valley	Kern	Line section	1 OH Switches, 3 OH Regulators,	2020	N	$9		2,045	83	12	28	251	2,419	WEEDPATCH 1102	Capacity	0.83	MW
Weedpatch 1106 - Install 100A regulator to correct low voltage of 116.8	Central Valley	Kern	Line section	1 OH Regulator	2019	N		$0.79	563	86	21	121	165	956	WEEDPATCH 1106	Voltage	0.98	Vpu
Wellfield 1104 - Install 200A regulator.	Central Valley	Kern	Line section	3 OH Regulators,	2019	N		$0.53	2	2	-	9	5	18	WELLFIELD 1104	Voltage	CC	Vpu
Camden 1105- Reconductor 9,000'	Central Valley	Fresno	Line section	9000FT. Reconductoring OH,	2020	N	$20		258	28	7	152	140	585	CAMDEN 1105	Capacity	CC	MW

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									Residential	Commercial	Industrial	Agricultural	Other	Total				
Midway 1103 - Install 200A regulator to correct low voltage of 116.7V	Central Valley	Kern	Line section	3 OH Regulators,	2019	N		$0.44	45	37	26	116	35	259	MIDWAY 1103	Voltage	CC	Vpu
Dairyland 1105 - Firebaugh 1102 Tie	Central Valley	Yosemite	Feeder	8200FT OF New OH Conductor, 1 OH Switches, 3 OH Regulators,	2021	N	$85		51	11	3	179	74	318	DAIRYLAND 1105 DAIRYLAND 1105	Capacity Capacity	CC CC	MW MW
Weedpatch 1102 - Remove Booster 4640 & install 300A close delta regulator	Central Valley	Kern	Feeder	1800FT. Reconductoring OH, 400FT OF New OH Conductor, 2 OH Switches, 3 OH Capactior Banks, 3 OH Regulators,	2019	N	$2,497		185	92	21	131	113	542	LAMONT 1102	Capacity	CC	MW
Tejon 1103- correct feeder overload and low voltage issue	Central Valley	Kern	Feeder	1 OH Switches, 1 OH Capactior Banks, 9 OH Regulators,	2019	N	$33		26	15	10	69	45	165	TEJON 1103	Capacity	CC	MW
LoadSEER_CVR_Newhall_TBD1	Central Valley	Yosemite	Line section	Installing a regulator to allow transfer	2020	N	$9		16	10	2	125	129	282	NEWHALL BANK 3 NEWHALL 1109	Capacity Capacity	CC CC	MW MW
Enable Madera 1119 to New Madera 1117 transfer	Central Valley	Yosemite	Line section	Install new switch	2021	N	$13		842	133	23	307	436	1,741	MADERA 1119	Capacity	0.47	MW
Ganso Bk1 Overload Relief	Central Valley	Kern	Line section	Reconductoring approx 4980ft of overhead conductor	2021	N	$16		30	15	3	101	31	180	GANSO BANK 1 GANSO 1104	Capacity Capacity	CC CC	MW MW
Bank 3 Overload	Central Valley	Kern	Bank	2 OH Switches, 3 OH Regulators,	2019	N	$8		3	2	1	23	11	40	SEMITROPIC 1112	Capacity	CC	MW
Newhall 1109 Overload Relief	Central Valley	Yosemite	Feeder	3 OH Regulators,	2019	N	$16		16	10	2	125	129	282	NEWHALL 1109	Capacity	CC	MW
El Capitan 2109- Replace OL LR disconnects 9420SB	Central Valley	Yosemite	Feeder	1 OH Recloser	2019	N	$3		3,182	248	96	-	202	3,728	EL CAPITAN 2109	Capacity	1.84	MW
Oakhurst 1101,1103, Coarsegold 2103 - Replace disconnect 10484, flying bell near fuse 69287 and SB 10536 with 900A switches.	Central Valley	Yosemite	Line section	3 OH Switches,	2019	N	$5		1,707	235	79	5	101	2,127	OAKHURST 1101	Capacity	0.87	MW
MAGUNDEN 1105 OVERLOAD CORRECTION	Central Valley	Kern	Line section	1 OH Switches,	2019	N	$4		2,109	94	26	-	26	2,255	MAGUNDEN 1105	Capacity	0.49	MW
BAKERSFIELD 2109 REPLACE OL DISCONNECT	Central Valley	Kern	Line section	1 OH Switches, 1 OH SCADA Switches,	2019	N	$2		4,666	453	127	-	57	5,303	BAKERSFIELD 2109	Capacity	1.70	MW

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									Residential	Commercial	Industrial	Agricultural	Other	Total				
Smyrna 1105- Low voltage Correction 117.6V	Central Valley	Kern	Line section	3 OH Regulators,	2019	N		$0.88	18	10	-	97	32	157	SMYRNA 1105	Voltage	CC	Vpu
Semitropic 1108 - Voltage Correction 117.9V	Central Valley	Kern	Line section	3 OH Capactior Banks, 3 OH Regulators,	2019	N		$0.53	4	5	-	32	8	49	SEMITROPIC 1108	Voltage	CC	Vpu
Goose Lake 1103 6 Cu Overload Correction (2023 Project)	Central Valley	Kern	Line section	3000 ft of reconductoring, 6 OH regulators	2019	N	$27		16	31	11	84	56	198	GOOSE LAKE 1103	Capacity	CC	MW
Charca 1106 Reconductor	Central Valley	Kern	Line section	80 feet UG cable w/out trench	2021	N	$71		1,999	143	19	33	146	2,340	CHARCA 1106	Capacity	0.25	MW
Plumas 1101 Reconductor	Northern	Sierra	Line section	Recond. 10,900' of various cond. with 715 AL, 2,800' of UG Cond. With 1100 AL EPR, 5 OH Switches, 2 Capacitors, & 3 Regulators	2019	N	$35		38	12	2	37	75	164	PLUMAS 1101	Capacity	CC	MW
Repl BB 8837 W/2-200A regs in O.D	Northern	North Valley	Line section	Repl BB 8837 W/2-200A regs in O.D	2019	N	$35		2,465	187	25	42	96	2,815	COTTONWOOD 1103	Capacity	0.16	MW
Santa Rosa 1102 Reconductor Feeder Outlet	Northern	North Coast	Line section	Recond. 1300' of 1000A XLP with 1100 CU EPR	2019	N	$10		3,916	194	75	-	232	4,417	SANTA ROSA A 1102	Capacity	1.32	MW
Santa Rosa 1103 Reconductor Feeder Outlet	Northern	North Coast	Line section	Recond. 930' of 1000A XLP with 1100 CU EPR	2019	N	$2		3,558	335	186	-	170	4,249	SANTA ROSA A 1103	Capacity	2.52	MW
Suisun 1101 - Replace 6,845ft of 700AL with 1100AL.	Northern	Sacramento	Line section	Replace 6,845' of 700AL with 1100AL.	2019	N	$24		785	168	68	-	21	1,042	SUISUN 1101	Capacity	CC	MW
R7 UPPER LAKE 1101 DIST LINE WORK.	Northern	North Coast	Line section	Recond. 3000'	2021	N	$49		790	140	19	84	46	1,079	UPPER LAKE BANK 1	Capacity	0.42	MW
Lincoln 1101 - Replace 80E fuses with Recloser due to Overload	Northern	Sierra	Line section	Replace 80E fuses with Recloser	2019	N	$33		2,025	274	70	26	146	2,541	LINCOLN 1101	Capacity	0.11	MW
Monroe 1105 Reconductor Feeder Outlet	Northern	North Coast	Line section	Recond. 1300' of 1000A XLP with 1100 CU EPR	2019	N	$7		5,258	168	49	1	148	5,624	MONROE 1105	Capacity	1.04	MW
Santa Rosa 1111 Reconductor Feeder Outlet	Northern	North Coast	Line section	Recond. 1200' of 1000A XLP with 1100 CU EPR	2019	N	$7		4,318	213	64	7	141	4,743	SANTA ROSA A 1111	Capacity	0.99	MW
SR 1107 & 1110 Reconfigure	Northern	North Coast	Bank	Recond. 11,300' of various cond. with 397 AL, 400' of UG Cond. With 1100 AL EPR, 1 UG Switch, & 1 UG J-Box	2019	N	$16		2,099	56	20	19	132	2,326	RINCON BANK 1 (TCAP'd)	Capacity	1.61	MW
															RINCON BANK 2	Capacity	0.87	MW
															SANTA ROSA A 1110	Capacity	0.83	MW
															RINCON 1101	Capacity	1.11	MW

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									Residential	Commercial	Industrial	Agricultural	Other	Total				
															RINCON 1103	Capacity	0.19	MW
EXTEND PLAINFIELD 1105	Northern	Sacramento	Line section	Recond. 9,200' of various cond. with 715 AL, 5600' of new 715 AL, 3,150' of UG Cond. With 1100 AL EPR, 1 New LR	2019	N	$44		2,392	52	4	16	327	2,791	WOODLAND 1103	Capacity	0.10	MW
															WOODLAND 1112	Capacity	0.59	MW
															PLAINFIELD 1106	Capacity	1.44	MW
Bellevue 2101 Replace Cable Outlet	Northern	North Coast	Feeder	Replace 200 feet of UG Cable w/out trench, Reconductor 1500 feet of OH	2020	N	$6		3,140	761	236	3	129	4,269	BELLEVUE 2101	Capacity	CC	MW
RECONDUCTOR 4AR, WINTERS 1102	Northern	Sacramento	Line section	Reconductor 5750 feet of overloaded #4Cu and #4AR. Winters 1102	2020	N	$92		147	29	6	92	94	368	WINTERS 1102	Capacity	0.31	MW
RECONDUCTOR 267AL ON GRANDISLAND 2226	Northern	Sacramento	Line section	Recond. 6,000' of 267 AL with 715 AL, 3 USB Switches	2019	N	$40		3,387	210	42	63	372	4,074	GRAND ISLAND 2226	Capacity	1.33	MW
Marysville 1105 Install new line section	Northern	Sierra	Line section	New install 2,800' of 397 AL, 2 USB Switches	2020	N	$10		2,923	172	27	52	449	3,623	OLIVEHURST 1103	Capacity	1.61	MW
Install 1 NOVA Recloser	Northern	Sacramento	Line section	Replace Fuse 4493 with NOVA Recloser	2020	N	$9		3,393	111	25	-	52	3,581	DAVIS 1105	Capacity	0.39	MW
Reconductor Corning 1102 feeder outlet	Northern	North Valley	Line section	Recond. 1,000' of 1000 AL XLP with 1100 AL EPR, 1 USB Switch	2020	N	$14		1,184	158	22	198	78	1,640	CORNING 1102	Capacity	CC	MW
Replace Vina Bank 1	Northern	North Valley	Bank	Install new 10.5 MVA Bank	2021	N	$509		84	25	7	13	1	130	VINA BANK 1	Capacity	CC	MW
Reconductor Calpella 1101	Northern	North Coast	Line section	Reconductor 7,000' of various conductor with 397 AL, Install 14,500' of New 715 AL, 7 USB Switches, 13 Fuse Locations, 6 Regulators, 2 LR's	2020	N	$2,139		1,255	163	19	24	62	1,523	CALPELLA 1101	Capacity	0.15	MW
Potter Valley PH 1104 Install LR at FCO 443	Northern	North Coast	Line section	Install 1 NOVA Recloser	2020	N	$9		237	31	1	30	17	316	POTTER VALLEY P H 1104	Capacity	CC	MW
Davis 1102 - Install tie	Northern	Sacramento	Line section	Install 850 feet oF UG cable in a new trench	2020	N	$11		3,145	135	50	-	58	3,388	Davis 1102	Reliability / Other	2.10	MW
Install Voltage Regulator	Northern	North Coast	Line section	Rincon 1101, Install Regulator near LR 576	2020	N		$0.91	3,038	123	29	6	101	3,297	RINCON 1101	Voltage	0.99	Vpu
Santa Rosa 1110, Install Regulator near SW 4625	Northern	North Coast	Line section	Install Voltage Regulator	2020	N		$0.91	4,803	161	19	-	61	5,044	SANTA ROSA A 1110	Voltage	0.99	Vpu

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Molino 1101, Reconductor 4900' of 4 CU	Northern	North Coast	Line section	Reconductor 4,900' of 4CU with 397 AL	2020	N	$71		4,550	396	68	78	62	5,154	MOLINO 1101	Capacity	0.37	MW
Corning 1102, Install Regulator near LR 38162	Northern	North Valley	Line section	Install 1 Regulator	2020	N		$0.28	1,184	158	22	198	78	1,640	CORNING 1102	Voltage	CC	Vpu
Corning 1103, Reconductor 3900' of 4/0 AL	Northern	North Valley	Line section	Reconductor 3900' of 4/0 AL with 715 AL, 1 set of regulators, 1 USB Switch	2020	N	$15		1,746	243	72	152	55	2,268	CORNING 1103	Capacity	1.64	MW
Plainfield 1101, Install Regulator near FCO 6733	Northern	Sacramento	Line section	Install 1 Regulator	2020	N		$0.91	1,692	109	17	57	98	1,973	Plainfield 1101	Voltage	0.99	Vpu
Plainfield 1105, Install Regulator near LR 8081	Northern	Sacramento	Line section	Install 1 Regulator	2020	N		$0.23	879	61	17	43	131	1,131	Plainfield 1105	Voltage	CC	Vpu
Woodland 1113, Install Regulator near LR 9422	Northern	Sacramento	Line section	Install 1 Regulator	2020	N		$0.39	75	40	56	16	47	234	Woodland 1113	Voltage	CC	Vpu
Woodland 1113, Replace SW 6107 & 8759 with USB's	Northern	Sacramento	Line section	Install 2 USB Switches	2020	N	$2		75	40	56	16	47	234	Woodland 1113	Capacity	CC	MW
Meridian 1101, Install Regulator near TS 4373	Northern	Sacramento	Line section	Install 1 Regulator	2020	N		$0.91	215	61	7	63	182	528	Meridian 1101	Voltage	0.99	Vpu
Install Bellevue Bk 1	Northern	North Coast	Bank	Install 45 MVA bank	2020	N	$33		7,805	1,204	376	3	238	9,626	Bellvue Bk 4	Reliability / Other	CC	MW
Install Logan Creek 2103 for CALAG MDF	Northern	North Valley	Feeder	Install new feeder breaker	2019	N	$173		730	204	24	203	44	1,205	LOGAN CREEK 2101	Capacity	1.53	MW
Install Bogue 1108	Northern	Sierra	Feeder	Install breaker and extend circuit	2021	N	$139		2,422	52	17	4	74	2,569	Bogue 1105	Reliability / Other	1.14	MW
Plumas 2107 Reconductoring	Northern	Sierra	Line section	Reconductor 1452 ' of 2C with 397AL	2020	N	$10		1,453	66	7	34	226	1,786	PLUMAS 2107	Capacity	0.77	MW
Hartley 1102 Reconductoring	Northern	North Coast	Line section	Reconductor 800 ' of 6C with 397AL	2020	N	$10		1,354	101	12	9	27	1,503	HARTLEY 1102	Capacity	0.37	MW
Lucerne 1103 Install Voltage Regulator	Northern	North Coast	Line section	Install 1 Regulator	2019	N		$0.92	1,999	193	23	26	55	2,296	LUCERNE 1103	Voltage	0.99	Vpu
Girvan 1101 Install Regulator	Northern	North Valley	Line section	Install 1 Regulator	2019	N		$0.78	1,163	123	13	6	48	1,353	GIRVAN 1101	Voltage	0.98	Vpu
Install tie	Northern	North Coast	Line section	1300' of UG in existing conduit, reconductor 1200', Install 600' tie	2021	N	$56		4,318	213	64	7	141	4,743	Santa Rosa A 1111	Reliability / Other	0.70	MW
Pleasant Grove 2109 Reconductor	Northern	Sierra	Line section	Reconductor 3300' of 1000 AL XLP with 1100 AL EPR	2021	N	$102		2,616	63	117	-	784	3,580	PLEASANT GROVE 2109	Capacity	0.38	MW

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West Sacramento 1109 Install USB Switch	Northern	Sacramento	Line section	Replace 1 USB Switch	2020	N	$3		3,326	118	22	66	62	3,594	WEST SACRAMENTO 1109	Capacity	1.55	MW
Install Line Regulator - Logan Creek 2102	Northern	North Valley	Line section	Install 1 Regulator	2021	N		$0.26	771	274	31	357	87	1,520	LOGAN CREEK 2102	Voltage	1.05	Vpu
Replace OH switch on Bogue 1105	Northern	Sierra	Line section	Install 1 USB Switch	2020	N	$1		2,422	52	17	4	74	2,569	BOGUE 1105	Capacity	1.09	MW

Appendix B Candidate Deferral Opportunities

									Expected performance and operational requirements									Customer Count					
Candidate Deferral Opportunity	Distribution Planning Region	Division	Project Type	Proposed Work	In-Service Date	Estimated LNBA Value ($/kW-yr)	Estimated LNBA Value ($/MWh-yr)	Unit Cost of Traditional Mitigation ($k)	GNA Facility Name	Distribution Service Required	Real Time (RA) or Day Ahead (DA)	Grid Need	Grid Need Unit	Month	Calls/ Year	Hours	Duration (Hours)	Residential	Commercial	Industrial	Agricultural	Other	Total
Santa Nella New Bank & Feeder	Central Valley	Yosemite	Bank	New 30 MVA Bank and new feeder	2022	$55	$78	$7,256	CANAL BANK 1	Capacity	DA	1.2	MW	Jun - Aug	75	5PM-9PM	4	4,987	576	193	167	-	5,923
									CANAL 1103	Capacity	DA	4.0	MW	Jun - Sept	122	3PM-10PM	7	2,693	89	22	81	-	2,885
									ORTIGA 1106	Capacity	DA	3.8	MW	Jun - Sept	122	4PM-10PM	6	2,299	211	55	208	-	2,773
									SANTA NELLA 1104	Capacity	DA	0.4	MW	Jul	22	7PM-9PM	2	720	86	38	129	-	973
Dairyland 1110 New Feeder	Central Valley	Yosemite	Feeder	Install new feeder on Dairyland	2022	$96	$24	$3,887	DAIRYLAND 1109	Capacity	DA	4.5	MW	May-Oct	168	12AM-12AM	24	137	55	5	321	-	518
Alpaugh New Feeder	Central Valley	Fresno	Feeder	Install new feeder at Alpaugh Substation	2022	$89	$88	$3,600	CORCORAN 1112	Capacity	DA	4.4	MW	Jun-Sep	113	3PM-12AM	9	2,458	124	22	46	-	2,650
Calflax Bank 2	Central Valley	Fresno	Bank	Install Calflax Bank 2	2023	$88	$60	$6,070	CALFLAX BANK 1	Capacity	DA	Customer Confidential						62	23	3	140	-	228
Pueblo Bank 3	Bay Area	North Bay	Bank	Install 45 MVA bank	2022	$21	$110	$6,936	Pueblo Bk 1	Reliability / Other	RT	23.2	MW	Apr-Oct	8	12AM-12AM	24	8,778	578	152	444	-	9,952
Camp Evers 2107	Central Coast	Central Coast	Feeder	Install breaker and extend circuit	2022	$202	$700	$1,720	Camp Evers 2106	Reliability / Other	RT	0.9	MW	Jan-Dec	12	12AM-12AM	24	5,740	533	92	5	-	6,370
FMC 1102	Central Coast	San Jose	Feeder	Install breaker and extend circuit	2023	$232	$805	$1,700	FMC 1101	Reliability / Other	RT	0.8	MW	Jan-Dec	12	12AM-12AM	24	2,927	345	150	-	-	3,422
Brentwood 2105	Bay Area	Diablo	Line section	Install 2500' of cable in existing conduit	2022	$59	$204	$640	Brentwood 2105	Reliability / Other	RT	1.2	MW	Jan-Dec	12	12AM-12AM	24	2,340	274	79	148	-	2,841
Avenal 2101	Central Valley	Fresno	Line section	200' tie and switches	2022	$6	$21	$65	Avenal 2101	Reliability / Other	RT	Customer Confidential						1,676	190	47	35	-	1,948
Rosedale 2102	Central Valley	Kern	Line section	Install 1750' of cable in existing conduit	2022	$24	$84	$400	Rosedale 2102	Reliability / Other	RT	1.8	MW	Jan-Dec	12	12AM-12AM	24	973	275	130	-	-	1,378
Madison 2101	Northern	Sacramento	Line section	Install 900' tie and switch	2022	$13	$45	$105	Madison 2101	Reliability / Other	RT	Customer Confidential						1,446	270	34	318	-	2,068
Peabody 2106	Northern	Sacramento	Line section	Reconductor OHL and new UG	2022	$8	$28	$390	Peabody 2106	Reliability / Other	RT	Customer Confidential						2,782	51	10	2	-	2,845
Martin SF H 1107	Bay Area	San Francisco	Line section	Replace 250' UG cable	2022	$4	$15	$150	Martin SF H 1107	Reliability / Other	RT	1.8	MW	Jan-Dec	12	12AM-12AM	24	6,675	374	41	-	-	7,090
Martin SF H 1108	Bay Area	San Francisco	Line section	Replace fuses with reclosers	2022	$9	$33	$180	Martin SF H 1108	Reliability / Other	RT	1.0	MW	Jan-Dec	12	12AM-12AM	24	6,414	264	38	-	-	6,716
Rob Roy 2105	Central Coast	Central Coast	Line section	Install 3000' new OH, switch, and recloser	2022	$18	$63	$500	Rob Roy 2105	Reliability / Other	RT	3.0	MW	Jan-Dec	12	12AM-12AM	24	7,325	627	92	12	-	8,056
Oceano 1106	Central Coast	Los Padres	Line section	Replace UG cable	2022	$18	$64	$425	Oceano 1106	Reliability / Other	RT	1.2	MW	Jan-Dec	12	12AM-12AM	24	5,828	848	90	45	-	6,811
Edenvale 2108	Central Coast	San Jose	Line section	Install SCADA MSO	2022	$7	$24	$95	Edenvale 2108	Reliability / Other	RT	1.5	MW	Jan-Dec	12	12AM-12AM	24	6,418	143	69	-	-	6,630
Estrella Substation	Central Coast	Los Padres	Substation	Construct Estrella Substation - 45 MVA transformer and fully populated switchgear enclosure	2024	$51	$359	$18,500	PASO ROBLES 1104	Capacity	RT	1.2	MW	Apr-Oct	8	12AM-12AM	4	2,306	418	118	80	-	2,922
									SAN MIGUEL BANK 1	Capacity	DA	3.6	MW	Apr-Oct	1	12AM-12AM	48	2,007	335	70	326	-	2,738
									TEMPLETON BANK 3	Capacity	RT	1.1	MW	Apr-Oct	8	12AM-12AM	24	7,311	1,071	338	300	-	9,020
									Cholame Between X14 and R96	Reliability / Other	RT	1.2	MW	Apr-Oct	8	12AM-12AM	4	134	19	-	43	29	225
									Cholame Sub DA	Reliability / Other	DA	11.8	MW	Apr-Oct	1	12AM-12AM	48	955	225	26	336	-	1,542
									Cholame Sub RT	Reliability / Other	RT		MW	Apr-Oct	8	12AM-12AM	24	955	225	26	336	-	1,542
									L/S R78 - Templeton 2109	Reliability / Other	RT	5.4	MW	Apr-Oct	8	12AM-12AM	4	1,385	72	18	71	71	1,617

File Creation Date: August 15, 2019

Appendix C Basis for Prioritization Metrics

Tier No	Candidate Deferral	Cost Effectiveness			Forecast Certainty			Market Assessment				
		Unit Cost ($k)	Estimated LNBA ($/kW-yr)	Estimated LNBA ($/MWh/yr)	Forecasted Need (Year)	SCADA Available (Y/N)	Customers on Asset	Real Time (RA) or Day Ahead (DA)	Days/ Year	Number of Grid Needs	Hours/Call	Overcapacity (%)
1	Alpaugh New Feeder	$3,600	$89	$88	2022	Y	2650	DA	113	1	9	38%
	Calflax Bank 2	$6,070	$88	$60	2023	Y	228	DA	CC	1	CC	CC
	Santa Nella New Bank & Feeder	$7,256	$55	$78	2022	Y	973	DA	122	4	7	36%
2	Camp Evers 2107	$1,720	$202	$700	2022	Y	6370	RT	12	1	24	3%
	FMC 1102	$1,700	$232	$805	2023	Y	3422	RT	12	1	24	4%
	Brentwood 2105	$640	$59	$204	2022	Y	2841	RT	12	1	24	6%
3	Estrella Substation	$18,500	$51	$359	2024	Y	225	RT	8	7	48	96%
	Pueblo Bank 3	$6,936	$21	$110	2022	Y	9952	RT	8	1	24	52%
	Oceano 1106	$425	$18	$64	2022	Y	6811	RT	12	1	24	8%
	Rosedale 2102	$400	$24	$84	2022	Y	1378	RT	12	1	24	9%
	Rob Roy 2105	$500	$18	$63	2022	Y	8056	RT	12	1	24	13%
	Peabody 2106	$390	$8	$28	2022	Y	2845	RT	CC	1	CC	CC
	Madison 2101	$105	$13	$45	2022	Y	2068	RT	CC	1	CC	CC
	Martin SF H 1108	$180	$9	$33	2022	Y	6716	RT	12	1	24	8%
	Martin SF H 1107	$150	$4	$15	2022	Y	7090	RT	12	1	24	18%
	Avenal 2101	$65	$6	$21	2022	Y	1948	RT	CC	1	CC	CC
	Edenvale 2108	$95	$7	$24	2022	Y	6630	RT	12	1	24	7%
	Dairyland 1110 New Feeder	$3,887	$96	$24	2022	Y	518	DA	168	1	24	34%

File Creation Date: August 15, 2019

Attachment B

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

DECLARATION SUPPORTING CONFIDENTIAL DESIGNATION
ON BEHALF OF
PACIFIC GAS AND ELECTRIC COMPANY (U 39 E)

1. I, Quinn Nakayama, am the Director of Integrated Grid Planning & Innovation at Pacific Gas and Electric Company ("PG&E"), a California corporation. Fong Wan, the Senior Vice President of Energy Policy and Procurement at PG&E, delegated authority to me to sign this declaration. My business office is located at:

   Pacific Gas and Electric Company
   77 Beale Street
   San Francisco, CA 94105

2. PG&E will produce the information identified in paragraph 3 of this Declaration to the California Public Utilities Commission ("CPUC") or departments within or contractors retained by the CPUC in response to a CPUC audit, data request, proceeding, or other CPUC request.

   Name or Docket No. of CPUC Proceeding (if applicable): R.14-08-013
3. Title and description of document(s): Distribution Deferral Opportunities Report (DDOR)
4. These documents contain confidential information that, based on my information and belief, has not been publicly disclosed. These documents are marked as confidential, and the basis for confidential treatment and where the confidential information is located on the documents are identified on the following chart.

Check	Basis for Confidential Treatment	Where Confidential Information is located on the documents
x	Customer-specific data, which may include demand, loads, names, addresses, and billing data (Protected under PUC § 8380; Civ. Code §§ 1798 *et seq.*; Govt. Code § 6254; Public Util. Code § 8380; Decisions (D.) 14-05-016, 04-08-055, 06-12-029)	Certain data in Distribution Deferral Opportunities Report per CPUC privacy rules adopated in D.14-05-016
	Personal information that identifies or describes an individual (including employees), which may include home address or phone number; SSN, driver's license, or passport numbers; education; financial matters; medical or employment history (not including PG&E job titles); and statements attributed to the individual (Protected under Civ. Code §§ 1798 *et seq.;* Govt. Code § 6254; 42 U.S.C. § 1320d-6; and General Order (G.O.) 77-M)	
	Physical facility, cyber-security sensitive, or critical energy infrastructure data, including without limitation critical energy infrastructure information (CEII) as defined by the regulations of the Federal Energy Regulatory Commission at 18 C.F.R. § 388.113 (Protected under Govt. Code § 6254(k), (ab); 6 U.S.C. § 131; 6 CFR § 29.2)	
	Proprietary and trade secret information or other intellectual property and protected market sensitive/competitive data (Protected under Civ. Code §§3426 *et seq.*; Govt. Code §§ 6254, *et seq*., e.g., 6254(e), 6254(k), 6254.15; Govt. Code § 6276.44; Evid. Code §1060; D.11-01-036)	
	Corporate financial records (Protected under Govt. Code §§ 6254(k), 6254.15)	

☐	Third-Party information subject to non-disclosure or confidentiality agreements or obligations (Protected under Govt. Code § 6254(k); see, e.g., CPUC D.11-01-036)	
☐	Other categories where disclosure would be against the public interest (Govt. Code § 6255(a))	

5. The importance of maintaining the confidentiality of this information outweighs any public interest in disclosure of this information. This information should be exempt from the public disclosure requirements under the Public Records Act and should be withheld from disclosure.
6. I declare under penalty of perjury that the foregoing is true, correct, and complete to the best of my knowledge.
7. Executed on this 15th day of August, 2019 at San Francisco, California.

Quinn Nakayama
Director, Integrated Grid Planning & Innovation
Pacific Gas and Electric Company